GE
Grid Automation

APPLICATION BOOK

CT REQUIREMENTS FOR GE MULTILIN RELAYS (R 6.9)

Contents

The specific and general recommendations suggested in this document were made based on general information that was used to perform the equipment electrical analysis under load and fault conditions for this specific application, and under applicable rules of protection.
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REV.	COMMENT	DATE	BY	SIGNATURE
6.0	First Issue with estimation of faults cleared In 100 ms.	25/11/2010	Jorge Cárdenas	
6.1	Estimation of faults cleared in 60 ms. Assuming breaker time of 40 ms and Relay time of 20 ms. Addition of a new Appendix (10)	22/08/2011	Jorge Cárdenas	
6.2	Inclusion of legacy relays	15/05/2012	Jorge Cárdenas	
6.3	Addition of formulas for 7.xx UR relays	08/01/2014	Mahesh Kumar	
6.4	Update of sections 8 & 10	23/07/2015	Jorge Cárdenas	
6.5	Update of Instantaneous OC section	23/12/2015	Mahesh Kumar	
6.6	850, 845, 869, and 889 relays added in the guide	07/10/2016	Lubo Sevov	
6.7	Revision of formulas in Section 1. OC functions. Example of incorrect trip in bus protection. Appendix on operation at low frequencies	12/12/2016	Jorge Cárdenas	
6.8	Replacing voltage level criteria with X/R	29/06/2017	Ilia Voloh	
6.9	Enhancement of MIB setting procedure with information from Robert Muziol (1-877 547 8630)	24/03/2018	Jorge Cárdenas	

CT REQUIREMENTS FOR GE MULTILIN RELAYS

1. Preface

The present book has been developed to help engineers and designers in the CT size calculation for the GE Multilin relays. The document contains invaluable information from real cases that have made possible to incorporate the experience in field and consequently, to improve the content. Thanks also to customers that sent to us interesting questions, hope the answers can fulfil their expectations.

Before to initiate the development of this interesting subject, we would like to clarify certain myths over CT calculation that still exist among the protection relay professionals:

a) CT saturation is only caused by a high current associated with a high relay burden: **False**. CT saturation is caused not only by a high current. CT saturation depends on other electrical parameters as well with one of the most important being the X/R ratio at the point of the relay installation. High X/R ratio produces high DC component, and therefore CT saturation can occur at relative low currents, in general less than 20 times of the nominal current as specified in most standards. The DC component during faults will cause the same CT to perform differently in a generation area or in a distribution area. The DC component is the reason for the CT to be dimensioned not only based on a symmetrical current (Ktf factor).

b) Relay burden has a significant influence in the CT saturation: **False**. In the electromechanical era, this was true, but today the relay impedance has a very low value. In majority of cases the relay resistance is much smaller than the leads resistance. The biggest influence is caused by the CT internal resistance (this resistance depends of the CT ratio, being higher with higher CT ratios) and for the leads that connect the CT with the relay. As an example, for CT ratios of 8000/1A, the CT resistance can have values higher than 10 ohms, while the relay resistance has only 0.2 ohms or less.

c) It is possible to do an “exact calculation” for CT dimensioning: **False**. There are not mathematical formulas to do an exact calculation, because the CT dimensioning is

based on CT saturation and this is a non-linear phenomenon associated with no constant parameters (Current, remanence, DC offset, etc.), and diverse operating conditions in the network.

d) The CT calculation criteria is independent of the protection function used: **False**. Some functions will be more affected by the CT saturation than other ones. In general, the differential functions are the most critical ones.

e) Correct CT dimensioning assures that the relay operation will be always in the CT linear region: **False**. It will be circumstances where the CT can work in the saturation region, particularly during internal faults. When a CT is dimensioned the main target is to assure that the relay will not trip incorrectly during external faults and it will trip correctly during internal faults. Many of the aspects developed here are strongly influenced by the engineering experience.

f) Relay settings have influence in the CT saturation: **False**. This is only valid for electromechanical relays because of the high burden associated with these devices while the pickup value is low. Numeric relays do not change the burden when changing relay settings. The CT behaviour has influence on the relay performance and in many cases, it is necessary to program the relays settings and characteristic, to avoid false tripping. One example is the percentage restrain in the differential characteristic used for Transformers, Generators, Busbars and Motors.

g) CT Saturation only occurs in the first cycle of the current when there is a high DC offset: **False**. With DC offset, the energy is accumulated faster in the CT than it can be delivered, as it depends of the previous CT condition (as remanence) and fault duration. This may or may not cause CT saturation in the first cycle after fault inception.

h) CT saturation only occurs during faults: **False**. CT saturation can also occur during motor starting or transformer energization, and it could be different for each phase, producing a “false” zero sequence current on its secondary side while the primary currents are perfectly balanced.

The references of this document are related to GE relays, but the topics developed are not exclusive of these relays. They can be applied to relays from other manufacturers, being only the limiting factor the experience of the relay engineer.

2. Introduction

The operation of protection is influenced by distortion in the measuring quantities that occurs when CTs saturate. Since it is not practically possible to avoid CTs saturation for all fault conditions, measurements measures must be taken to determine the degree of saturation, which still allows proper protection operation.

Different considerations should be taken depending on the application of the protection and on the setting range available for each specific protection.

For high voltage applications and protections operating instantaneously, such as distance, line differential, transformer differential or instantaneous over current, the transient response of the CT must be considered. An over dimensioning factor, taking into account the primary system time constant, secondary circuit time constant and minimum time of un-saturated signal required by the relay will be calculated.

For medium and low voltage applications and protections operating as definite time over current or inverse time over current, the transient response is usually neglected, due to the lower requirements in terms of operating times.

The guide contains formulas and suggestions to be used case by case considering the type of CT and the relay model. The considerations mentioned in this guide are valid for IEC, ANSI, BS CTs. The formulas have shall to be used on case by case basis considering the international standard selected for the used CTs. The suggested safety factors are conservative to cover all the very severe conditions such caused by as AC and DC current dc components, harmonics distortions, etc. In case of heavy fault conditions, a detailed analysis using all based on CT details, all the primary and secondary circuit characteristics and the algorithms of the selected protection function, are strongly suggested.

3. Definitions and general approach

The following terms are used in this document:

- I_n: Nominal secondary current.
- P_n: Nominal Accuracy Power of the CT
- n: Nominal Accuracy limit factor (ALF) of the CT
- P_r: Power associated to the relay burden, at In.
- P_{ct}: Internal Power consumption of the CT at In.
- R_{ct} : Internal secondary CT resistance.
- n': Real Accuracy limit factor of the CT, associated to its real burden.
- n_t: Transient Accuracy limit factor of the CT.
- K_{tf} : CT Over-dimensioning factor.
- t: Response time of the protection relay.
- T_p: Primary time constant.
- T_s: Secondary circuit time constant.
- I_f: Secondary Fault current.
- I_s: Pick up setting in the relay (secondary).
- R_L: Leads resistance.
- R_p: Protection relay resistance.
- R_b: (R_L + R_p): Total burden connected on the secondary
- V_{kp}: Voltage at knee-point. That point on the magnetizing curve where an increase of 10% in the flux density (voltage) causes an increase of 50% in the magnetizing force (current)..

Note: the standards define the CTs with different technical data. The main applied standards are IEC, ANSI, BS.

For a given CT, 20VA 5P20:

Accuracy Power: P_n = 20 VA

Accuracy Limit Factor: n = 20

Accuracy Class: 5P, meaning that it is a CT for protection applications, with a transformation error lower than 5% for currents lower than 20 times the nominal current.

The real accuracy limit factor (n') describes the real limit of the linear region of the CT for a given burden, different from the nominal burden.

The formula is as follows:

$$n' = n * (P_n + P_{ct}) / (P_r + P_{ct})$$

Transient accuracy limit factor considers the transient response of the CT and the decaying DC component of the fault current.

The Appendix 2 explains all the theory supporting the use of the different Over-dimensioning factors. In General, we can say that the Ktf factors recommended are as follows (analysis must be done for external faults):

Protected Element	**Ktf**	
Transmission Lines	8	General application*
	4-5	Lines with X/R<20
	4	L90
Transformers	7	Generator step-up transformers
	4	General application

Generators

- DGP relays: → K_{tf} = 12

  Higher values are rarely needed because of the percentage restrain principle.
- G30 relays: → K_{tf} = 12

  Higher values are rarely needed because of the percentage restrain principle.
- SR489 relays: → K_{tf} = 8 for generator > 100MVA

  K_{tf} = 6 for generator up to 100MVA

  →K_{tf}= 4 for generators up to 30 MVA
- G60 and 889 relays: → K_{tf} = 8 for generator > 100MVA

  → K_{tf} = 6 for generator > 30MVA up to 100MVA

  → K_{tf} = 4 for generator up to 30MVA

GE differential relays such as UR G60, G30, T60/T35(f/w 7.40 and up), M60, 889, 845, 869 offering percentage differential protection by programming a differential/restraint principle characteristic, with saturation detection algorithm, and directional (phase comparison) principal, can tolerate lower Ktf. factors.

Busbars relays (B30, B90, B95) CT Saturation time higher than 0.125 * cycle.

* in case of transmission lines with more than 2 bundled conductors per phase. In these cases, the X/R (positive sequence) ratio can be as high as 25 for 500 kV lines. For short HV Transmission lines (230 kV and up and less than 10 Km) connecting Generator Power plants, a criterion similar to the one for generators (Ktf=12) is recommended.

Note 1: The above criteria is only valid for low impedance relays, because in low impedance schemes, operation in the linear portion of the saturation curve is critical during external faults. During internal faults, the CTs could saturate but it is necessary only to assure that the relay will receive enough signal level to operate. In general, if the saturation is severe, it is only necessary to consider time inverse over current relays that could be affected in their coordination with other over current relays. In this case, additional setting calculation may be required or the adoption of other measures as voltage restraint. Additional comments on this subject are given in the Appendix 1 and in the reference 6.

Note 2: For CT saturation analysis, it is necessary to establish some limits such as the minimum saturation time. There are no fixed rules, but in general the CT must not saturate for at least 1/4 of a cycle to enable most of the newer GE relay differential protection algorithms to detect external fault condition. For bus protective relays, 0.125 cycle saturation free time is enough to detect external fault conditions.

Note 3: In the Appendix 4 we describe the criteria used to calculate the CTs for GE high impedance relays.

Note 4: As a rule analysis for CT saturation in internal faults only apply for Overcurrent functions (Points 4 & 5). For other functions the analysis must be done for external faults.

Note 5: the Ktf values are conservative and they can be calculated case by case according to the formula on page 39

For L90 and D60: $V_{kp} > 2 * I_f * (R_{ct} + R_L + R_p)$ X/R>20

For L90 and D60: $V_{kp} > 1.0 * I_f * (R_{ct} + R_L + R_p)$ X/R<20

For T60/ T35: $V_{kp} > 4 * I_{ft} * (R_{ct} + R_L + R_p)$

For T60/T35 with X/R <20 system: Vkp>2*

Where:

V_k: CT Knee point voltage

I_f: Fault current at CT secondary

I_{ft}: Fault current considering transformer impedance

R_{ct} : CT secondary resistance

R_L: Lead resistance

R_p: Relay burden/resistance

Table 1: Reference of the main GE relays.

MAIN RELAYS AND PAGES THAT APPLY

Relay Model	***Main Function***	***Page***	***Notes***
G60, 889	*Generator Differential*	*24*	
489, G650	*Generator Differential*	*24*	
G30, DGP	*Generator Differential*	*24*	
MTP/DTP	*Transformer Differential*	*19*	
T60, T35, 745, 845, 345	*Transformer Differential*	*19*	*Predominant Function*
	Overcurrent	*14*	*OC criteria applies only if the CT is not used for differential*
B30/B90	*Bus Protection*	*26*	
MIB, BUS1000	*Bus Protection*	*52*	
TLS, DLP, D60, D90	*Distance Protection*	*17*	
D30	*Distance Protection*	*17*	
DLS·, L30, L90, L60	*Line Differential & Phase comparison Protection*	*21*	*L60 has less requirements. It can be estimated as for 66 kV*
DMS	*Feeder Protection*	*14, 15*	
F35/F60, 850 N60	*Feeder Protection*	*14, 15*	*N60 is not a feeder protection and it has lower requirements, but it can be estimated at the OC values*
MIF/SMOR	*Feeder Protection*	*14, 15*	
350, 750	*Feeder Protection*	*14, 15*	

F650	*Feeder Protection*	*14, 15*	
DBF, C60, C90	*Breaker Failure Protection & Controller*	*14, 15*	
C70	*Capacitor Bank Protection*	*14, 15*	
M60, 869	*Motor Protection*	*14, 15, 65*	
MIG, MIW	*Motor Protection*	*14, 15, 65*	
469	*Motor Protection*	*14, 15, 65*	
369	*Motor Protection*	*14, 15, 65*	
269	*Motor Protection*	*14, 15, 65*	
MM2	*Motor Protection*	*14, 15, 65*	
MM3	*Motor Protection*	*14, 15, 65*	

4. Instantaneous or Definite Time Over Current Protection

Definite time over current protections operate on a fixed set time for currents greater than the value of the pickup setting, independently on the value of the current. (Instantaneous is a particular case of Definite Time, with intentional delay set to zero).

Definite Time Over current elements are encountered in main and backup protection relays, as well as in breaker failure relays, etc.

For definite time overcurrent applications, a given CT is adequate if the maximum current (per unit) seen by the relay is less than n'

For low impedance faults, current magnitude is expected to be very high and the relay is accounted for trip as one of the CT will provide unsaturated signal only for few milli seconds. Below formula is recommended for the CT's that shall have at least 5ms of unsaturated waveform with intentional time delay programmed. CT dimensioning Knee point voltage can be calculated as follows:

To directly compute Vkp for this application, the formulas are as follows:

$V_{kp} > K_{tf} * I_x * (R_{ct} + R_L + R_p)$ for three-phase faults

$V_{kp} > K_{tf} * I_x * (R_{ct} + 2R_L + R_p)$ for single-phase-to-ground faults

I_x =min (K1, I_{fs}) where *K1=160 for F650, 20 for UR,SR3 and 8 series*)

$K_{tf} = 1.0$

and then, the power of the CT will be as follows:

$$P = \left[V_{kp} / (n * I_n) - R_{ct}\right] * I_n^2$$

5. Inverse Time Overcurrent Protection

The operating time of an inverse time over current protection is a function of the current magnitude, and as such it is strongly dependant on the correct measurement of the fault current. The associated CT therefore must ensure a linear response over the complete range of the curve, or up to the maximum fault current, whichever is smaller.

To evaluate if a given CT is adequate for an inverse time over current protection application, n' must be greater than:

$$n' > 0.5 * I_{\max curve} / I_n \quad or \quad n' > 0.5 * I_f / I_n$$

where $I_{maxcurve}$ is the limit value for which the relay starts responding as definite time. (A security margin of 1.5 has been applied)

To directly compute Vkp for this application, the formula is as follows:

$V_{kp} = 0.5 * I_{\max curve}(R_{ct} + R_L + R_p)$ for three-phase faults

$V_{kp} = 0.5 * I_{\max curve}(R_{ct} + 2R_L + R_p)$ for single-phase-to-ground faults

or

$V_{kp} = 0.5 * I_f * (R_{ct} + R_L + R_p)$ for three-phase faults

$V_{kp} = 0.5 * I_f * (R_{ct} + 2R_L + R_p)$ for single-phase-to-ground faults

and then, taking the minimum of these two voltages, the power of the CT will be as follows:

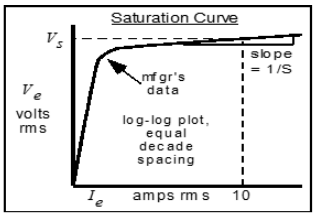
$$P = \left[V_{kp} / (n * I_n) - R_{ct}\right] * I_n^2$$

Notes:

CT calculation never can be considered as an exact exercise, because the influence of all phenomena associated as X/R ratio, DC offset, remanence, among others. Impact in the use of a minor VA in OC relays is to increase relay operation time by some few cycles, if CT saturates deeply; but relay operation is always guaranteed, including with very high short circuit current values. See picture enclosed for operation details.

IPUT PARAMETERS:

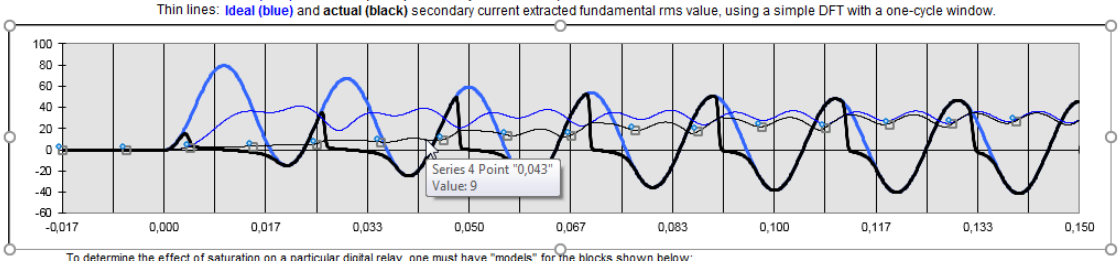
		ENTER:	
Inverse of sat. curve slope =	S =	22	---
RMS voltage at 10A exc. current =	Vs =	173,6	volts rms
Turns ratio = n2/1=	N =	1200	---
Winding resistance =	Rw =	4,750	ohms
Burden resistance =	Rb =	0,245	ohms
Burden reactance =	Xb =	0,000	ohms
System X/R ratio =	XoverR =	15,0	---
Per unit offset in primary current =	Off =	1,00	-1<Off<1
Per unit remanence (based on Vs) =	λrem	0,80	---
Symmetrical primary fault current =	Ip =	37.200	amps rms



CALCULATED:

Rt =	Total burden resistance = Rw + Rb =	4,9
pf =	Total burden power factor =	1,0
Zb =	Total burden impedance =	4,9
Tau1 =	System time constant =	0,0
Lamsat =	Peak flux-linkages corresponding to Vs	0,7
ω =	Radian freq =	314
RP =	Rms-to-peak ratio =	0,34
A =	Coefficient in instantaneous ie versus lambda curve: ie = A * l^S :	6,49
dt =	Time step =	0,00
Lb =	Burden inductance =	0,00

Thick lines: **Ideal (blue)** and **actual (black)** secondary current in amps vs time in seconds.
Thin lines: **Ideal (blue)** and **actual (black)** secondary current extracted fundamental rms value, using a simple DFT with a one-cycle window.



To determine the effect of saturation on a particular digital relay, one must have "models" for the blocks shown below:

6. Distance protection

Distance relays are used in more critical applications than are over current relays, and must operate very fast, during the transient period (first cycles) of the fault. Due to the nature of this application, the use of the transient over dimensioning factor is required.

Because the operation of the Zone 1 is in general faster than one cycle in internal faults with large currents, the check for CT saturation will be addressed to analyse the performance of the zone 2.

We can say that zone 2 starts at the reach limit of Zone 1. If we have relative long lines (in the order of 50 km and above), the X/R ratio from the source is dictated by the X/R of the line. In this condition a Ktf between 4 to 8 will minimize the effect of CT performance in the relay reach

Relays applied on Short lines could under reach during a certain time (transmission lines with bundled conductor with more than 2 conductors per phase could have X/R ratio as high as 25 for 500 kV, and they could be affected), but because the DC component decays significantly after 50 to 100 ms (Zone 2 normally is delayed for more than 300 ms), the Ktf value suggested can be maintained.

The knee voltages would be:

At the reach limit of Zone 1: $V_{kp} = K_{tf} * I_f * (R_{ct} + R_L + R_p)$

and the power of the CT would be:

$$P = \left[V_{kp} / (n * I_n) - R_{ct}\right] * I_n^2$$

For modern distance protection relays such as ALPS and D60 use 10 ms as response time (t). In this case, Ktf will be = 3 for faults inside the reach point.

The equations shown above correspond to the worst condition possible for the fault current containing maximum DC offset. It is normal practice to apply a reduction factor (RF) from 0.5 to 0.7 to these requirements, as only 60% or less DC is encountered in most of the faults. The reduction factors are recommended to be applied as follows:

66 to 145 kV: 0.7

Under 66 kV: 0.5

$$V_{kp} = K_{tf} * I_{f1} * (R_{ct} + R_L + R_p) * RF$$

Note 1:

- R_{CT} burden considered = 2 Ω (R_L=1 Ω (200m of 4mm2 copper cable); R_p=0.2 Ω). R_{ct} will depend of the CT ratio and the secondary rated value (1 A or 5 A).

Note 2:

For L90 and D60: (X/R >20): $V_{kp} > 2 * I_f * (R_{ct} + R_L + R_p)$

For L90 and D60: X/R<20: $V_{kp} > I_f * (R_{ct} + R_L + R_p)$

7. Transformer Differential protection

Differential relays must remain stable for through fault current until the corresponding upstream/downstream protective relay clears the fault (i.e. 60 ms).

Transient response is critical, and the transient over dimensioning factor must be considered for through faults (external faults). The mentioned condition must be fulfilled at both sides of the power transformer. For relays using a percentage restraint principle, and enhanced security for saturation detection and directional phase comparison, the experience shows that the requirement for Ktf factor can be normally reduced by a factor of 2. These percentage restraint algorithms (T60/T35- f/w 7.40 and up, 845) help to avoid the operation during external fault, even with maximum DC offset, providing that the saturation free time is not less than 1/2 cycle.

We need to differentiate between Step-up Power transformers (Power transformers located close to the generators) and other transformers.

- If it is a Generator Step-up Power transformer, then Ktf = 12 must be used for relays that do not employ percentage restraint in the differential algorithms.
- If it is a Sub transmission or Distribution Power transformer then it is more reasonable the use of a lower value as Ktf = 8 for relays that do not employ percentage restraint in the differential algorithms.

As mentioned above, when applying relays that use percentage restraint algorithms with enhanced security, the above values can be reduced to the following:

- X/R>20: Ktf = 7
- X/R<20: Ktf = 4

To estimate the power of the CTs, and ensure stability for external faults, the following calculations are done on each side of the power transformer.

Knowing the K_{tf} value, The knee voltage needed to ensure stability for through faults will be:

$$V_{kp} = K_{tf} * I_f * (R_{ct} + R_L + R_p)$$

and the power of the CT would be:

$$P = \left[V_{kp} / (n * I_n) - R_{ct}\right] * I_n^2$$

Equations shown above correspond to the worst condition possible for the fault current containing maximum DC offset. It is usually a normal practice to apply a reduction factor (RF) from 0.5 to 0.7 to these requirements, as only 60% or less DC is encountered in most of the faults. The reduction factors are recommended to be applied as follows:

66 to 145 kV: 0.7

Under 66 kV: 0.5

Note 1: In case of Step-up transformers connected directly with the generator, the analysis normally is only needed for faults in the HV side, because faults in the LV side will corresponds to faults on the generator terminals and in these cases the generator and the transformer normally are disconnected (it is important to know where the breakers are installed). Analysis at both sides are needed if the step-up transformer is connected several Generators in parallel, each with its corresponding CB.

Note 2:

- R_{CT} burden considered = 2 Ω (R$_L$=1 Ω (200m of 4mm2 copper cable); R$_p$=0.2 Ω). R_{ct} will depend of the CT ratio and the secondary rated value (1 A or 5 A).

- : $V_{kp} > 4 * I_f * (R_{ct} + R_L + R_p)$

  For X/R<20 system: Vkp=2..*

8. Line Differential protection

Line differential protection is a critical application that requires a relay operating in a very fast and secure manner.

As in case of Transformer protection, the analysis must be done for through external faults. To compute the power requirements for the associated CTs, the transient performance must be considered.

The regular calculation can be done by using the transient over dimensioning factor as previously. In the case of L90 a Ktf = 4 can be used. For EHV transmission lines this may be increased to 5. For legacy relays as DLS3 values closer than the ones used for transformers are recommended. This means Ktf = 7 for lines close to generation points and Ktf=4 for lines in sub-transmission and distribution areas. Special care must be taken in case of transmission lines with bundle conductor with more than 2 conductors per phase. In these cases, the X/R (positive sequence) ratio can be as high as 25 for 500 kV lines (In these cases, a Ktf value of 8 is warranted). For short HV Transmission lines (230 kV and up and less than 10 Km) connecting generating plants, a criterion like the one for generators is recommended (Ktf=12).

The knee voltage would be:

$$V_{kp} = K_{tf} * I_f * (R_{ct} + R_L + R_p)$$

and the power of the CT would be:

$$P = \left[V_{kp} / (n * I_n) - R_{ct}\right] * I_n^2$$

Equations shown above correspond to the worst condition possible for the fault current containing maximum DC offset. It is usually a normal practice to apply a reduction factor (RF) from 0.5 to 0.7 to these requirements, as only 60% or less DC is encountered in most of the faults. The reduction factors are recommended to be applied as follows:

66 to 145 kV: 0.7

Under 66 kV: 0.5

$$V_{kp} = K_{tf} * I_{f1} * (R_{ct} + R_L + R_p) * RF$$

Please check the recommendations given in the instruction manual of the relay, if applicable, for more detailed information.

Note 1 :

- R_{CT} burden considered = 2 Ω (R_L=1 Ω (200m of 4mm2 copper cable); R_p=0.2 Ω). R_{ct} will depend of the CT ratio and the secondary rated value (1 A or 5 A).

Note 2: The criteria is based in having equal CT ratios at both ends of the line. In case of different CT ratios, additional analysis and verifications are needed. See the Appendix 8 (Q & A) for more details.

Note 3: UR ver7.x relays are designed with high speed CPU with faster response time. The following CT sizing formulas apply for UR ver 7.xx:

For L90 (X/R>20) : $V_{kp} > 2 * I_f * (R_{ct} + R_L + R_p)$

For L90 (X/R<20) : : $V_{kp} > I_f * (R_{ct} + R_L + R_p)$

When for diverse circumstances, the existing transformers did not fit with the above requirements, it is recommended to do a check using the tool existing in the website named:

" L90 CT Saturation Analysis" http://www.gedigitalenergy.com/app/ViewFiles.aspx?prod=l90&type=9)

This is an excel tool that allows user to verify dynamic CT performance under different operating circumstances, combined with relay settings. In that way, the CT calculations can be verified and also optimized.

External Fault Behind: CT4 System Frequency: 60 Hz

CT Parameters	CT1	CT2	CT3	CT4	
Inverse of sat. curve slope	25	25	25	25	
Sec. voltage (Vs) at 10A exc. current	800	800	800	800	V
CT Primary	1200	1200	1200	1200	A
CT Secondary	5A	5A	5A	5A	
Primary system X/R ratio	35	35	35	35	
Total CT burden resistance	1	1	1	1	ohms
CT burden reactance	0,01	0,01	0,01	0,01	ohms
Per unit DC offset in primary current	1	1	1	1	
Per unit remanence	0	0	0	0	
Symmetrical primary fault current (Ip)	5000	10000	5000	20000	A

L90 Settings		
Pickup	0,2	pu
Restraint 1	30	%
Restraint 2	50	%
Break point	2	pu

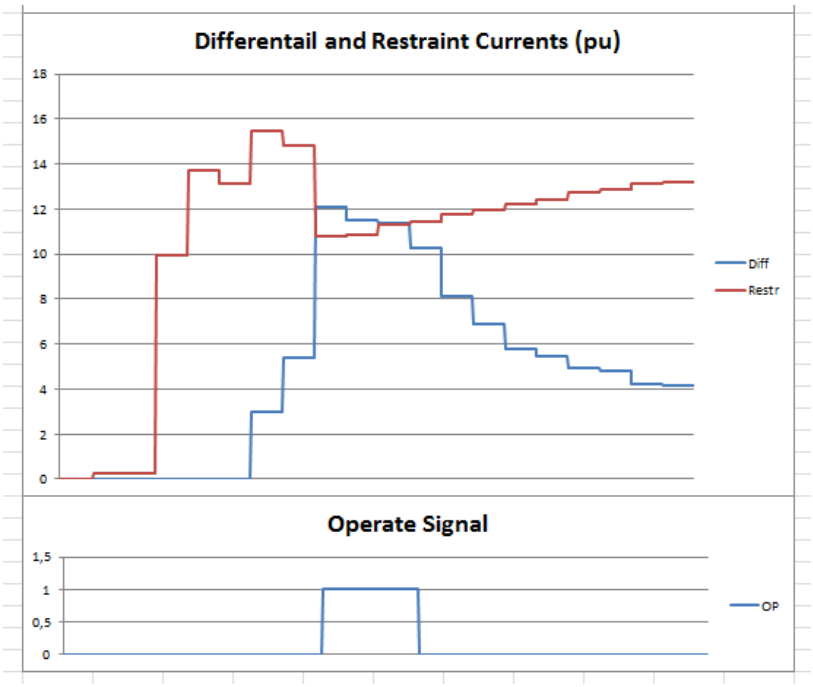


Figure A. Visualization of results from L90 Operation tool.

9. Generator Differential protection

Generator differential relays must remain stable for through faults and must operate rapidly for internal faults.

CT transient response is critical, and the transient over dimensioning factor must be therefore considered.

This over dimensioning factor should depend upon on both: above detailed features of generator differential protection relays (stability for through fault conditions, and rapid operation for during internal fault conditions) but, as a general rule, for CT sizing and verification purposes, just the requirements relevant to stability for on through faults condition are to be considered. , being that ones relevant to operation for internal faults extremely restrictive and leading to very over dimensioned CTs.

Thus, the following over dimensioning factors are recommended:

- DGP relays: → $K_{tf} = 12$

  Higher values are rarely needed because of the percentage restrain principle.
- G30 relays: → $K_{tf} = 12$

  Higher values are rarely needed because of the percentage restrain principle.
- SR489 relays: → $K_{tf} = 8$ for generator > 100MVA

  $K_{tf} = 6$ for generator up to 100MVA

  → $K_{tf} = 4$ for generators up to 30 MVA

  Higher values are rarely needed because of the percentage restrain principle, the saturation detection algorithm and the directional (phase comparison) algorithm.
- G60, 889 relays: → $K_{tf} = 8$ for generator > 100MVA

  → $K_{tf} = 6$ for generator > 30MVA up to 100MVA

  → $K_{tf} = 4$ for generator up to 30MVA

  Higher values are rarely needed because of the percentage restrain principle, the saturation detection algorithm and the directional (phase comparison) algorithm.

Notes:

1. With special regards to SR489, G60 and 889 relays, K_{tf} is bigger for larger generators because of the X/R of the generator themselves: for generators with rated power up to 30MVA X/R is approximately 15, while for generators with rated power higher than

100MVA X/R is higher than 60. The X/R ratio has big impact on the performance of the directional algorithm when the saturation is high.

2. For suitable and reliable differential protection operation, the following settings of the G60, or 889 differential elements are moreover recommended:
   - Slope 1 = 40%
   - Break 1 = 1.2pu
   - Slope 2 = 80%
   - Break 2 = 4

To calculate the knee point voltage and the burden of the CTs suitable for generator differential protection application, the following calculations are then to be done:

$$V_{kp} = K_{tf} * I_f * (R_{ct} + R_L + R_p)$$

$$P = \left[V_{kp} / (n * I_n) - R_{ct}\right] * I_n^2$$

V_{kp} is the CT knee point voltage needed to ensure stability for through faults.

P is the CT burden calculated from V_{kp}.

Note 1: Depending where the CB´s are located, the short circuit current used frequently corresponds to faults on the HV side of the step-up transformer.

Note 2:

- R_{CT} burden considered = 2 Ω (R_L=1 Ω (200m of 4mm2 copper cable); R_p=0.2 Ω). R_{ct} will depend of the CT ratio and the secondary rated value (1 A or 5 A).

10.Low Impedance Busbar Protection

The criteria for CT dimensioning in B90 and B30 relays is based on the CT saturation time, using the following equation:

$$T_{sat} = -T_{dc} \ln\left(1 - \frac{(V_{sat} / I_s R_s - 1)}{\omega T_{dc}}\right) > 2{,}5ms\,(50\,Hz)\,or\,2\,ms\,(60\,Hz)$$

where:

T_{sat} = Saturation time

T_{dc} = Network time constant to consider the DC component (Chapter 9 of the B90 manual)

V_{sat} = Knee point in the CT saturation curve

I_s = RMS secondary short circuit current

$R_s = R_{ct} + R_L + R_p$

R_{ct} = CT secondary resistance (ohms)

R_L = Leads resistance (complete loop)

R_p = Burden resistance (usually 0.2 ohm)

$\omega = 2\pi f$ being f = frequency

B90 and B30 algorithms are warranty to operate correctly within this requirement. See Application of Settings (Chapter 9 of the B90 manual).

Note: With this criterion we assure correct operation of directional element and saturation detector, providing the correspond security against external faults that could cause CT saturation a consequently a possible operation of the differential element.
We recognize that the above criteria are very conservative, because it starts from the assumption of full DC offset and Ktf factor with its final value (w/o considering relay operating time).

To do a more realistic approach, an excel tool is available in our website “CT time-to-saturate Estimator”

http://www.gedigitalenergy.com/app/ViewFiles.aspx?prod=b90&type=9

With this tool it is possible to calculate a more approximate value of saturation time, than the one obtained from the general criteria described above.

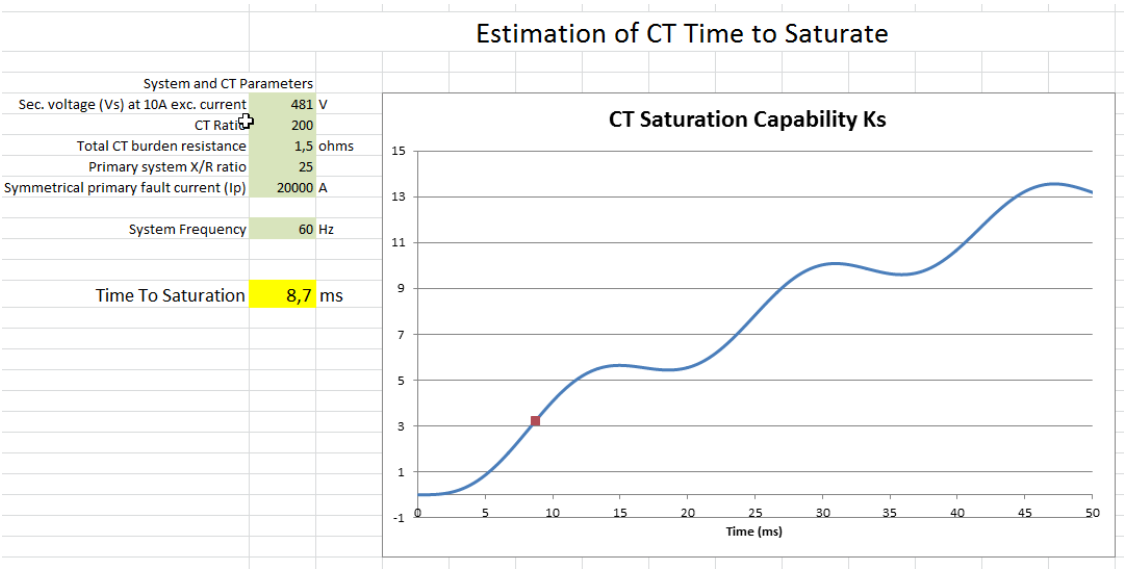


Figure B. Visualization of results from Excel tool

APPENDIX 1

Criteria for CT verification during internal faults

In general, and with a CT saturated it will be enough a signal magnitude sufficient to allows a correct relay operation. There are some functions that could have affected its operation as follows:

a) Operation time in the Inverse time overcurrent relay because the reduction of the effective value caused by the CT saturation

b) Reach reduction in the distance relays, particularly in the time delayed zones. First zone is rarely affected because in general its operation is produced before the CT saturates. See Point 6 for additional clarifications

c) Differential protection is also rarely affected if the relays has been dimensioned properly for external faults. If we assume an internal fault just on the terminals of the first set of CT´s, this CT´s could saturate because a large current, but the CT´s in the opposite side will not. In this way and in the worst condition, the differential current value will be the one provided by the remote end. Having in count that the setting of the differential unit rarely exceeds 0.3 p.u., it will be a sufficient current to assure a correct trip. In the other hand, as the fault current increase, the response of the algorithm will be faster and before the CT saturates. In case of single infeed, the performance of the differential algorithm is like an instantaneous overcurrent element

In an instantaneous overcurrent relay for any practical multiple of pickup, the response time (the response time is the time to decide to operate, that is different that the relay operating time) may be approximated with reasonable accuracy by the following equation [10].

$$t_{PKP} = \frac{1.33}{MOP}$$

where t_{PKP} is a pickup time in power system cycles and MOP is a multiple of pickup (actual current / pickup threshold).

For example, for a MOP of 4, the magnitude estimated by a relay will reach a pickup level after 1.33 / 4 = 0.33 of a power system cycle. Even if a main CT saturates after this time completely, the instantaneous overcurrent is guaranteed to operate. Consequently, the following equation describes a condition guaranteeing operation of an instantaneous overcurrent element before CT saturation for the relays:

$$t_{PKP} < T_{sat} \qquad T_{sat} = -T_{DC} \ln\left(1 - \frac{(V_{sat} / I_s R_s - 1)}{\omega T_{DC}}\right)$$

where:

T_{sat} = Saturation time

T_{DC} = Network time constant to consider the DC component (Chapter 9 of the B90 manual)

V_{sat} = Knee point in the CT saturation curve

I_s = RMS secondary short circuit current

$R_s = R_{ct} + R_L + R_p$

R_{ct} = CT secondary resistance (ohms)

R_L = Leads resistance (complete loop)

R_p = Burden resistance (usually 0.2 ohm)

$\omega = 2\pi f$ being f = frequency

$V_{sat} = R_s I_s \left[1 + \frac{X}{R}\left(1 - e^{-t_{PKP}/T_{DC}}\right)\right]$, $T_{DC} = \frac{L}{R}$ in seconds. t_{PKP} also, must be given in seconds

Example:

Consider a system with the following characteristics:

- CT: 400 V, = 0.8 ohm, 50% residual magnetism
- System: X/R ratio of 35
- Fault: = 50 A secondary
- Instantaneous overcurrent settings: Pickup threshold = 20 A secondary

Now, given a 400 V saturation voltage with 50% residual magnetism in a CT core, we have the CT saturation voltage as:

$$V_{sat} = 400Vx(1-0.5) = 200V$$

The T_{DC} time constant for 60 Hz is calculated as follows:

$$\frac{X}{R} = 35 \rightarrow \frac{L}{R} = \frac{35}{2\pi\, x\, 60\, Hz} = 0.093\, s \rightarrow T_{DC} = 93\, ms$$

The multiple of pickup is:

$$MOP = \frac{50\, A}{20\, A} = 2.5$$

Now, time to saturation = 11.3 ms and time to pickup $= \frac{(1.33\, x\, 16.666\, ms)}{2.5} = 8.9\, ms.$

The instantaneous overcurrent will pickup before the CT saturates.

Once a main CT saturates, the waveform distorts and the magnitude of the fundamental frequency component is reduced. Having the saturation curve of the CT available, one may estimate the actual secondary current seen by the relay and confirm if a given instantaneous overcurrent would pickup on a saturated waveform.

For illustration the following figure shows a saturated waveform, the magnitude of the fundamental frequency component as measured by the UR-series relay and the true RMS value.

Additional information about the OC performance during CT saturation can be found in the reference (6)

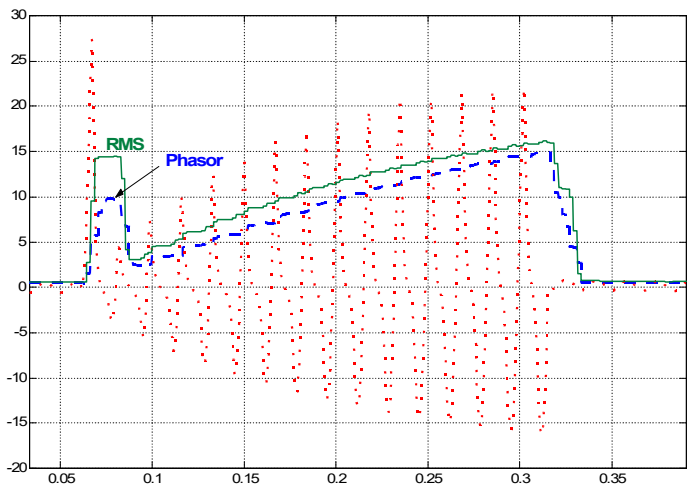


Figure 1.1. Effective signal for tripping during internal faults with CT saturated

The above methodology gives us only a reference approach. In general, CTs only slightly reduce short circuit tripping capabilities of GE Multilin's relays. Given the typically applied settings, there is no danger of a failure to trip from instantaneous overcurrent functions even in extreme cases of very high short-circuit currents and low-ratio CTs (6). Reference (6) explains why one does not encounter the problem of no operation in the field. On the surface the problem seems to be very serious – the secondary currents are extremely low compared with the ratio currents. However, these secondary currents are still high enough to activate relays given their practical setting ranges. In the same reference there are cases where the secondary current was 1080 times the nominal one and still under this condition with extremely saturation, relays were capable to operate. For that, the calculation methodology proposed for internal faults must not be applied as mandatory in the CT dimensioning being the correct criteria to analyse internal and external faults (the last ones with the corresponding fault current) and to give preference to the value calculated for external faults or to select the minor of the two values.

APPENDIX 2

Dimensioning of Current Transformers (CT) for Application in Protection

1. CT Fundamentals

Basic Transformers consist of two windings magnetically coupled by the flux in a saturable steel core. A time varying voltage applied to one winding drives magnetic flux in the core, and induces a voltage in the second winding. The transformer draws an exciting current to maintain the flux in the core.

Since AC voltage is time varying, the flux, the exciting current and the voltage and current induced in the second winding is also time varying.

A current transformer is simply a transformer designed for the specific application of converting primary current to a secondary level for measurement purposes. The actual performance of a CT, and the equivalent model used for analysis purposes, are identical to that of any other transformer, as shown in Figure 2.1

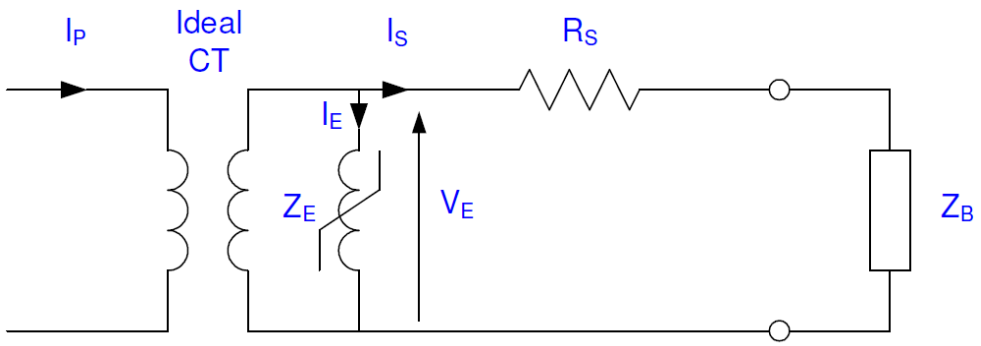


Figure 2.1 CT Equivalent Circuit

The concern for the relay engineer is the actual current at the secondary terminals of the CT: This current I_s, is the total secondary current as transformed by the CT, I_{sTotal}, minus the current necessary to supply the magnetizing branch I_E.

2. CT saturation

A short circuit occurring on the primary circuit has a great impact on the performance of a CT. The increase in primary current results in an increased secondary current. The increased secondary current results in a higher voltage across the CT winding resistance and connected burden of the CT, and results in a higher excitation voltage. This higher excitation voltage creates more flux. The flux characteristic is still sinusoidal in shape, but may be high enough to cause saturation of the transformer core. The resulting exciting current needed

to supply the flux is very high in magnitude, and may approach the magnitude of the primary fault currents. As $I_s = I_{s\,Total} - I_E$, the current output of the secondary winding is reduced significantly by the higher exciting current. The core goes into and out of saturation as the voltage varies over the power system cycle. As a result, the output of the CT is normal while the core is unsaturated and reduced when the core saturates, as in Figure 2.3.

As described, the excitation voltage induces flux in the CT core, and the flux is supplied by the excitation current. CT manufacturers supply the secondary excitation characteristic to relate excitation voltage and excitation current for a specific model of CT. This characteristic is used to estimate CT performance for protective relaying applications. This characteristic, for example, can be used to determine the excitation voltage at which the CT will saturate.

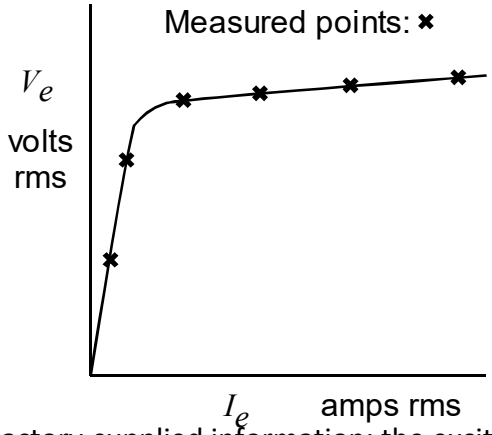
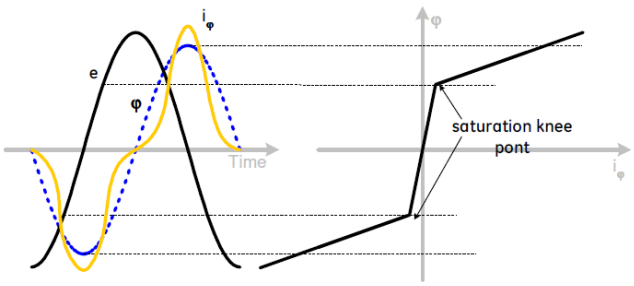


Figure 2.2 Factory-supplied information: the excitation curve.



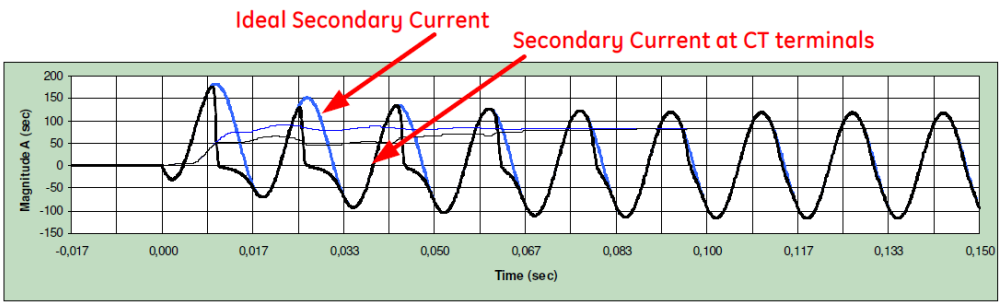


Figure 2.3 Measured Secondary CT current during saturation

This saturation voltage V_x is the symmetrical voltage across the secondary winding of the current transformer for which the peak induction just exceeds the saturation flux density. It is found graphically by locating the intersection of the straight portions of the excitation curve on log-log axes. When the excitation voltage of the transformer exceeds this level, the transformer core is in saturation. The saturation voltage is important to predicting CT performance during fault conditions.

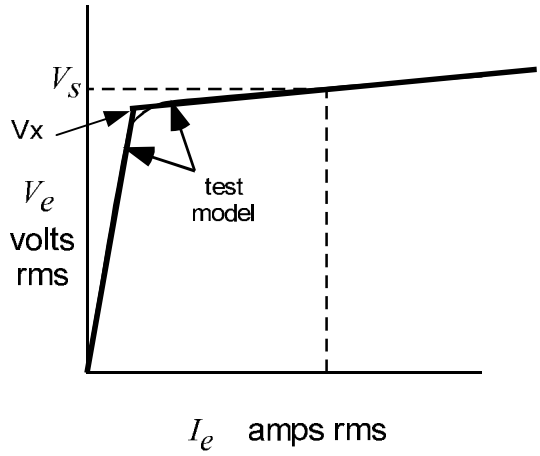


Figure 2.4 . CT saturation voltage from secondary excitation characteristics.

3. DC Offset

In the highly inductive network of the power system, the current wave must be near maximum when the voltage wave is zero. Therefore, when a short circuit occurs with the instantaneous voltage at zero, the current at the time of the fault must be at a maximum. To supply this maximum current, a counter current, the DC component, is produced. After providing this initial current requirement, the DC component is no longer required, and decays based on the X/R ratio of the power system. The practical result is during short circuits the primary current, and therefore the secondary current, may be asymmetrical with respect to the current axis. This asymmetrical current results in the peak current that will be seen for a specific fault, ad is known as the DC offset of the fault current.

This DC component is a problem for transformers, as the DC component tends to create more flux in the core that adds to the flux driven but the AC voltage. So essentially, the total flux in the CT is dependent on the area under the curve. Therefore, the longer the system time constant, the more likely the CT is to saturate

4. Remnant flux

The flux in the core of a CT is a function of both the excitation voltage, and the magnetic properties of the core itself. When excitation is removed from the CT, some of the magnetic

domains of the core retain a degree orientation relative to the magnetic field that was applied to the core. This is known as remnant flux. When excitation is removed during high magnitude fault events, this remnant flux can be quite high. The remnant flux essentially shifts the normal operating flux of the CT, and will require either more or less exciting current. During a subsequent fault, this remnant flux can push the core deeper into saturation, or keep the core from going as deep into saturation.

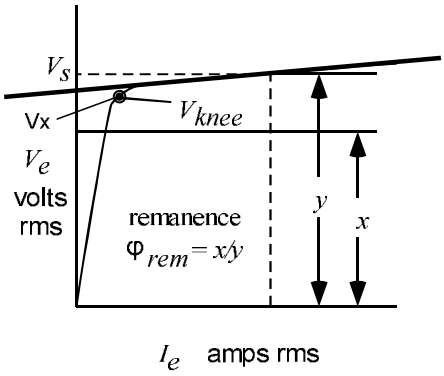


Figure 2.5 Definition of per unit remanence

5. Transients on Current Transformers – Fundamentals

It is essential that the protection functions respond correctly to the short circuit current in the first few cycles of the fault. As such, is necessary to determine the over-sizing of the CT required to avoid saturation due to the asymmetrical (or DC) component of the waveform

The initial value of this dc offset depends on the voltage incidence angle (the voltage value when the fault occurs), and the peak value will be $\sqrt{2}*I_{sc}$, where I_{sc} is the rms value of the short-circuit symmetrical current.

Considering this maximum value, the transient short-circuit current is defined by the following equation:

$$i_{(t)} = I * Sin\left(\omega t + \alpha - \theta\right) - I * Sin\left(\alpha - \theta\right) * e^{-t/Tp} \qquad (1)$$

Where:

I = Peak value of current

ω = $2 * \pi * f$

α = Angle on voltage wave at which fault occurs

θ = Arctan (ω*L/R)

T_p = L/R (of power system)

The equation (1) becomes:

$$\varphi_T = \varphi_A\left[\omega T_p\left(1 - e^{-ts/Tp}\right) - Sin\omega t\right] \quad (2)$$

The following general expression can be obtained assuming that the secondary CT burden is essentially resistive, and considering the CT time constant.

$$\varphi_T = \varphi_A\left[\frac{\omega T_p T_s}{Ts - T_p}\left(e^{\frac{-ts}{Ts}} - e^{\frac{-ts}{Tp}}\right) - Sin\,\omega t\right] \quad (3)$$

Where:

T_s = CT time constant

φ_A = Peak value of symmetrical ac flux

Finally, for $T_s >> T_p$ (typical in normal CTs) and CTs with without air-gaps

Because the load and wiring is mainly resistive, let be Sin ωt = -1, and t_s (relay response time + Circuit breaker operating time) is normally much higher than Tp, then the equation (3) can be reduced to:

$$\varphi_T = \varphi_A(\omega T_p + 1) \quad (4)$$

During faults the CT will be forced to develop a flux necessary to feed fault current to the secondary with two components: the exponential (dc offset asymmetrical component) and the ac component (symmetrical component). The resultant voltage must be higher than that necessary to feed the load connected in the secondary side of CTs without distortions caused by saturation. Hence the necessary oversize factor Ks is defined by:

$$\varphi_{transient} = \varphi_{DC} + \varphi_{AC} = K_s * \varphi_{AC}$$

Where the over dimensioning or transient factor is:

$$K_s = \omega T_1\left(1 - e^{\frac{-ts}{Tp}}\right) - Sin\omega t \quad (5)$$

6. Resultant CT Secondary Voltage during Faults

In general, testing and experience have shown that the performance of many relays will not be adversely affected by moderate degrees of CT saturation. However, since it is not economically feasible to test and determine the performance of all types of relays with different degrees of saturation, it is common practice to specify CT requirements for various protective schemes. The requirement generally specified is that the CTs should not saturate before the relays operate for some specified fault location.

To meet these criteria, calculating the minimum required saturation voltage could specify the required transient performance for a current transformer. In general different standards as IEC 185, IEC 44-6, BS3938 or ANSI/IEEE C5713 fix this voltage by the general expression:

$$V_{kp} = k_0 * k_{tf} * k_R * I_2 * R_2 \qquad (6)$$

Where:

V_{kp} = saturation voltage as defined by the intersection point of the extensions of the straight-line portions (the unsaturated and the saturated regions) of the excitation curve

I_2 = Symmetrical fault current in secondary Amperes

R_2 = Total secondary resistive burden including CT secondary, wiring loop resistance, lead resistance and load resistance. This value includes the return path for secondary current when ground faults are considered.

K_{tf} = Saturation or transient factor = $\frac{\omega T_p T_s}{T_s - T_p}\left(e^{\frac{-t_s}{T_s}} - e^{\frac{-t_s}{T_p}}\right) + 1$ (as per Eq. 2) in the simplified version, with fully offset

and $\left[\frac{\omega T_p T_s}{T_s - T_p}\left(e^{\frac{-t_s}{T_s}} - e^{\frac{-t_s}{T_p}}\right) - Sin\,\omega t\right]$ in the exact version.

T_s = Secondary circuit time constant

T_p = Time constant of the dc component of fault component. It is equal to the X/R ratio of the system.

ω = System angular frequency

t_s = Time to saturation. This is the period from fault initiation until CT saturation starts to occur. . If this value is less than the relay operating time then the impact of CT saturation must be considered.

K_0 = Represents the effect of the offset present during the fault. This offset is a function of the fault incidence angle, which is maximum at zero voltage (0º or 180º). Experience indicates that when the incidence angle of the faulted voltage is near 90º lower offset effect is produced. Therefore this factor will apply in those cases where offset exceeds 0.5 p.u

K_R = Remnant flux factor. The remnant flux can be left in the core due the following:

- The exciting current leads the load current by 90º and thereby under normal control open commands, the load current is cut near or at zero crosses, but the exciting current in the CT has significant value.
- DC tests performed on the CTs
- The effect of the dc component on offset fault currents (exponential component) that are interrupted when tripping the circuit breaker.

The equation (2) is valid for CTs with air-gapped cores because of their low magnetizing impedance and resulting low secondary time constant, T_2. The air-gaps used in CTs tend to reduce drastically the effect of the remnant flux left in the core due its lower magnetizing impedance and correspondingly much lower secondary time constant. The effect of the remnant flux is also to reduce the time to saturation. In fact, remnant flux could help or hurt you although the latter case is the determining factor. This factor may vary from 1.4 to 2.6 times the rated flux in the core.

For closed-core CTs (normal CTs), the secondary time constant T_2 is very high ($L_{magnetizing} \approx \infty$ before saturation), allowing it to be dropped from equation (5) resulting in a conservative value for time to saturation.

7. Criteria definition for CT selection.

To establish a criterion to CT selection, some preliminary calculations have been made in order to determine the influence of the X/R ratio in the CT performance.

The equations used to calculate the K factor are as follows:

$$K_{tf} = \left[\frac{\omega T_p T_s}{T_s - T_p} \left(e^{\frac{-t_s}{T_s}} - e^{\frac{-t_s}{T_p}} \right) - Sin\,\omega t \right]$$ in the detailed model

$$K_{td} = \left[\frac{\omega T_p T_s}{T_s - T_p} \left(e^{\frac{-t_s}{T_s}} - e^{\frac{-t_s}{T_p}} \right) + 1 \right]$$ in the simplified and more conservative version

The results are shown in the following Fig.

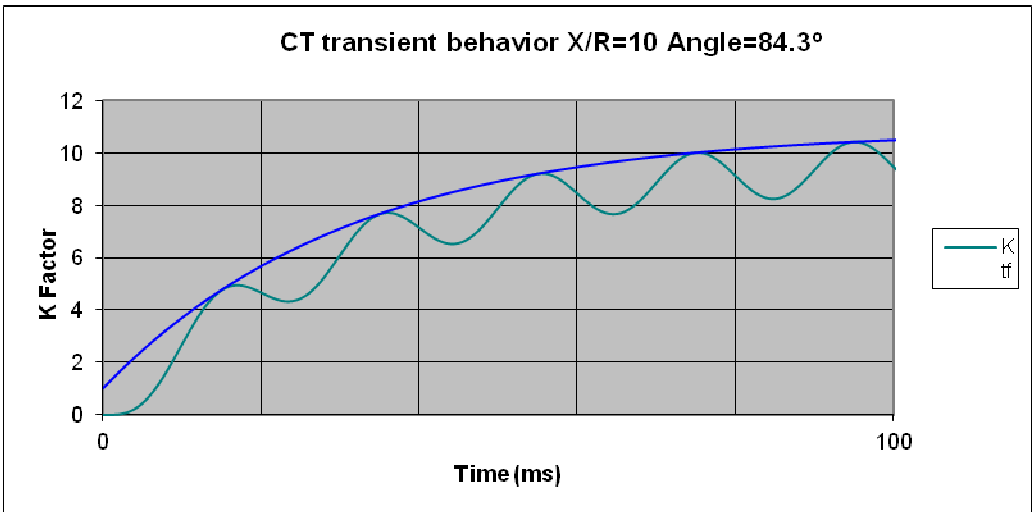


Fig. 2.6A

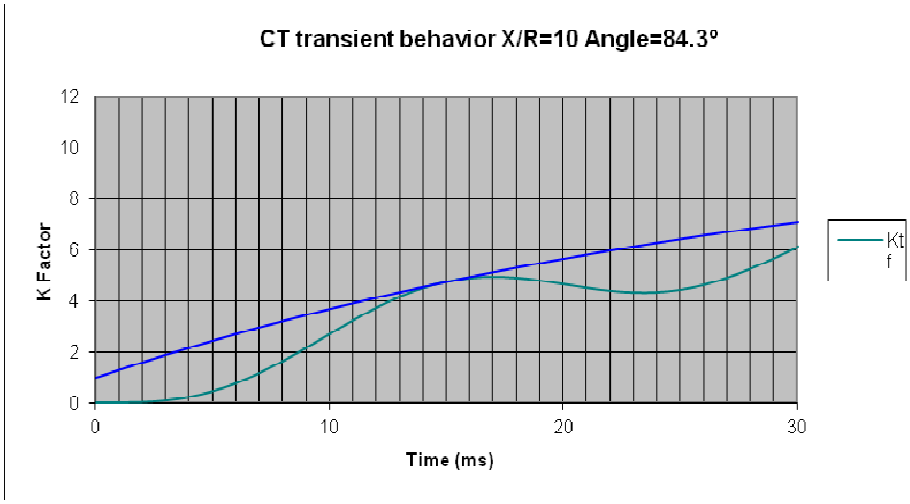


Fig. 2.6B Detail in the first 30 ms.

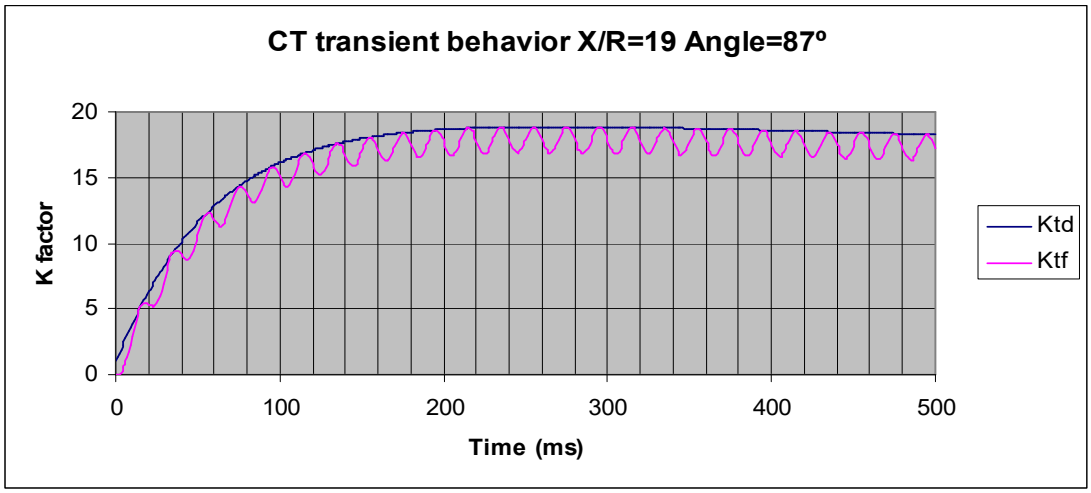


Fig. 2.7A

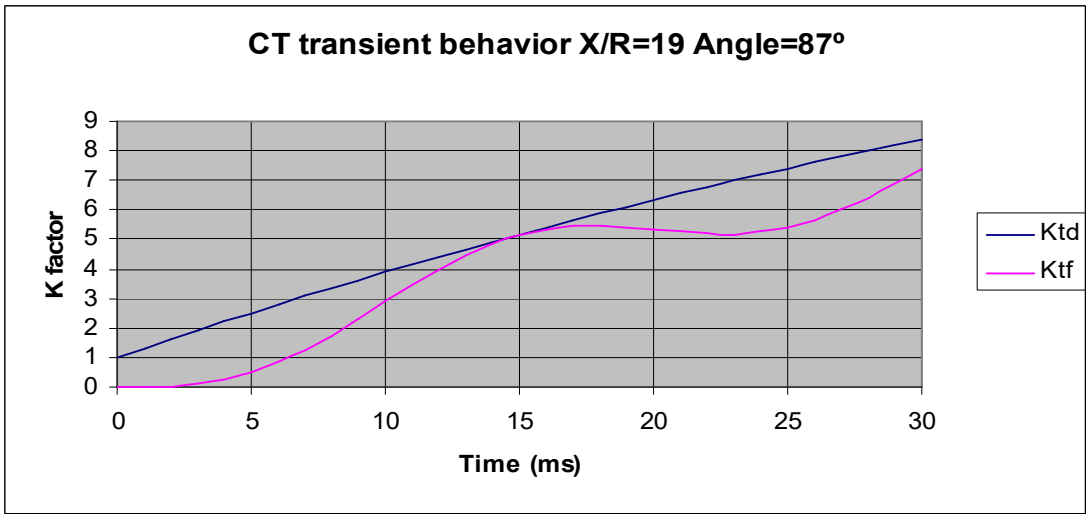


Fig. 2.7B (Detail of the first 30 ms)

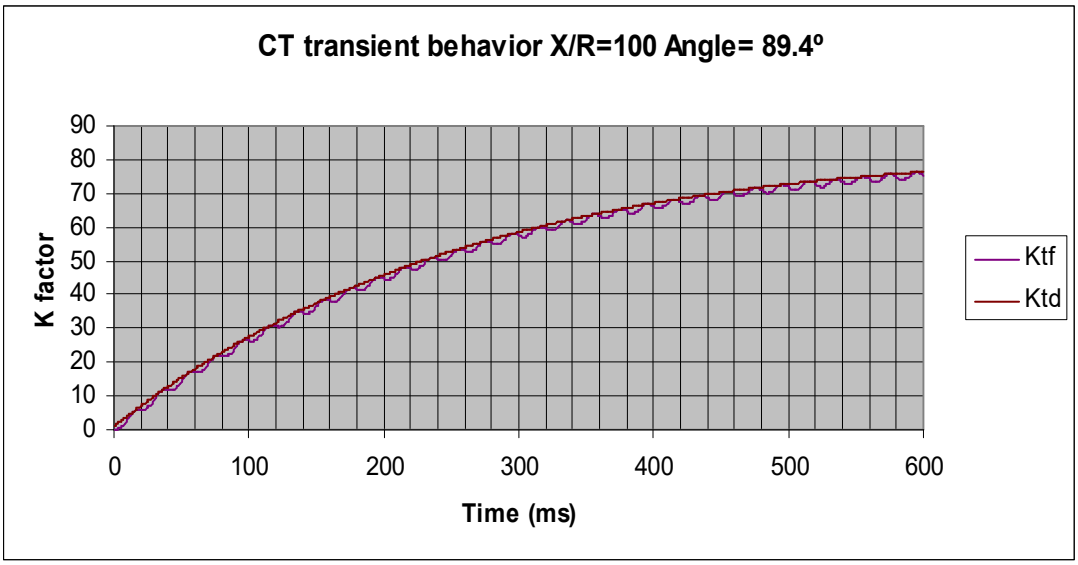


Fig 2.8A

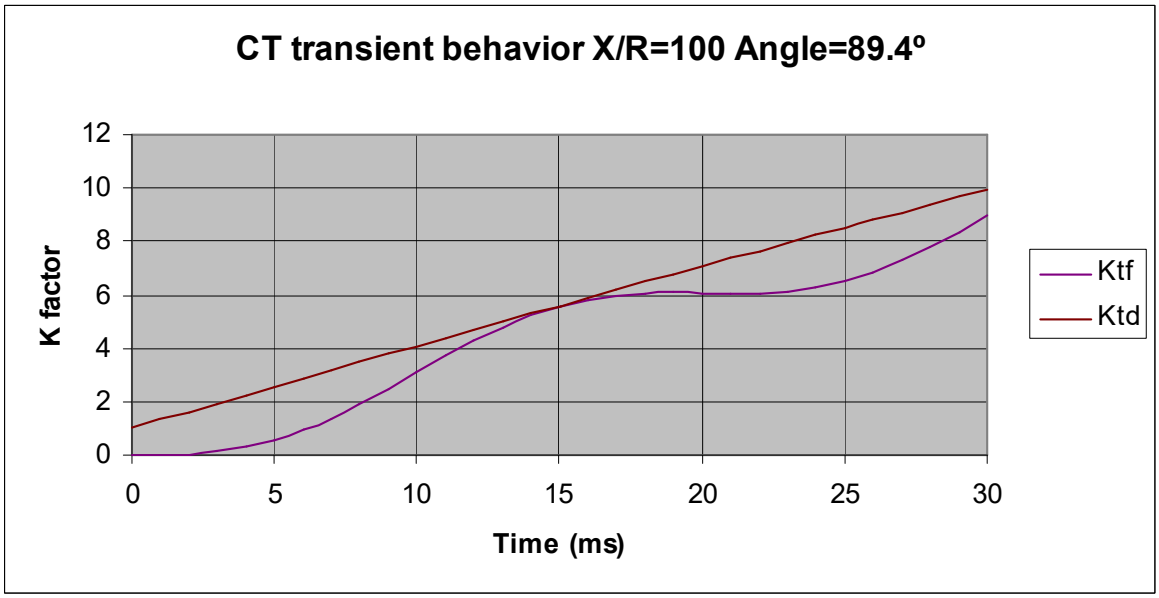


Fig 2.8B (Detail of the first 30 ms)

The decrement or rate of decay of the d-c component is proportional to the ratio of reactance to resistance of the complete circuit from the generator (source) to the fault point.

If the ratio of reactance to resistance is infinite (i.e zero resistance), the d-c component never decays. On the other hand, if the ratio is zero (all resistance, no reactance), it decays immediately. For any ratio of reactance to resistance in between these limits, the d-c component takes a definite time to decrease to zero.

In generators the ratio of sub transient reactance to resistance may be as much as 70:1; so it takes several cycles for the d-c component to disappear. In circuits remote from generators, the ratio of reactance to resistance is lower, and the d-c component decays more rapidly. The higher the resistance in proportion to the reactance, the more I^2R loss from the d-c component, and the energy of the direct current is dissipated sooner.

It is often said that generators, motors, or circuits have a certain d-c time constant. This refers again to the rate of decay of the d-c component**.** The d-c time constant is the time, in seconds, required by the d-c component to reduce to about 37% of its original value at the instant of short circuit. It is the ratio of the inductance in Henrys [V∗s/A] to the resistance in Ohms (Ω) of the machine or circuit. This is merely a guide to show how fast the d-c component decays.

From Figures 2.6 to 2.8 some interesting conclusions can be obtained:

1. The Ktf factor is practically independent of the system X/R ratio for times lower than 25 ms. This is an interesting point because the decision time to trip is made within 15 ms in most of the protection functions (we refer to decision time to trip and not the time to trip because after the relay has decided to trip, no CT saturation behaviour will change that decision). In the Appendix 1 we have a methodology to calculate the Ktf value for internal faults.

2. For fault clearing times in the order of 60 100 ms. we can see differences in the Ktf and Ktd factors that are dependent on the X/R value. The most affected relays are the differential relays which need to ensure a non-tripping condition during external faults. Values of Ktf can go from 12 for X/R = 16 to 18 for X/R = 100. The main question here is what is the value that can ensure correct performance minimizing at the same time the CT requirements? Before answering that question, we can take a look at Table 1 and Table 2 from Appendix 3, where we can see the typical X/R ratios for lines, generators and transformers.

From the above, some interesting points can be analysed:

- Transmission Lines: The maximum X/R (positive sequence) ratio occurs for EHV transmission lines (500 kV and up), with a value of 10 regarded as a reasonable assumption in case no other value is available. This value corresponds with an angle of 84.3º, the value expected for the majority of transmission lines. In this case, the Ktf recommended for 60 ms is equal to 8. The other advantage in transmission lines is the short circuit drop because of the line impedance. Special care must be taken in case of transmission lines with bundle conductor with more than 2 conductors per phase. In these cases, the X/R (positive sequence) ratio can be as high as 25 for 500 kV lines. For short HV Transmission lines (230 kV and up and less than 10 Km) connecting Generator Power plants, a criterion similar to the one for Generators is recommended.

- Power transformers: From Fig. 3.1 we can see that X/R ratio for Power transformers is 40 as a medium value (88.6º) for large transformers. Based on this value, we can say that Ktf is around of 15 (this value will depend where the Power transformer is located). As the transmission lines, we have the advantage of the Power transformer impedance when an external fault is analysed:

    1. If it is a Generator Step-up Power transformer, then Ktf = 15 must be used if there is no percentage restraint in the differential algorithms.

    2. If it is a Sub transmission or Distribution Power transformer then it is more reasonable the use of a lower value as Ktf = 8 (Similar to the transmission line).

- Generators: Here the X/R values in general are high. In table 2 we can observe values from 40 to 120 being a typical X/R value = 80. Based on that values Ktf could be as high as20. If there are differential algorithms with percentage restrain or other algorithms do not affect by saturation (directional algorithms), this value can be considerable lower.

As a conclusion we can recommend in general, the following Ktf values for external faults with clearing time higher than 60 ms:

- Transmission lines: Ktf = 8 (It can be reduced to 4 in the case of L90 relay). Transmission lines with voltages higher than 230 kV with bundle conductors and connected to Generator Power plants need special care. See the above comments.
- Step-up Power Transformers: Ktf = 7
- Other Power transformers: Ktf =4
- Generators: Ktf = 12 (It can be reduced to 8 in case of G60)
- Busbars: Ktf = 6. Ktf = 4 for voltages lower than 132 kV. For B90, because the directional criteria, the analysis is made based on the saturation time. See point 10
- Internal faults with instantaneous trip free of saturation: See Appendix 1 For other algorithms as the differential one, also lower values can be used in the analysis, because in general the short circuit current values will be sufficient high to provide enough signal magnitude to allow the operation of the algorithm during internal faults with one CT saturated.

From the above values we can conclude that the higher requirements are on Step-up Power transformers and on Generators.

The Short circuit current decrement factor acts favourably to reduce the Ktf requirements in Generators as we shown on Fig. 2.9.

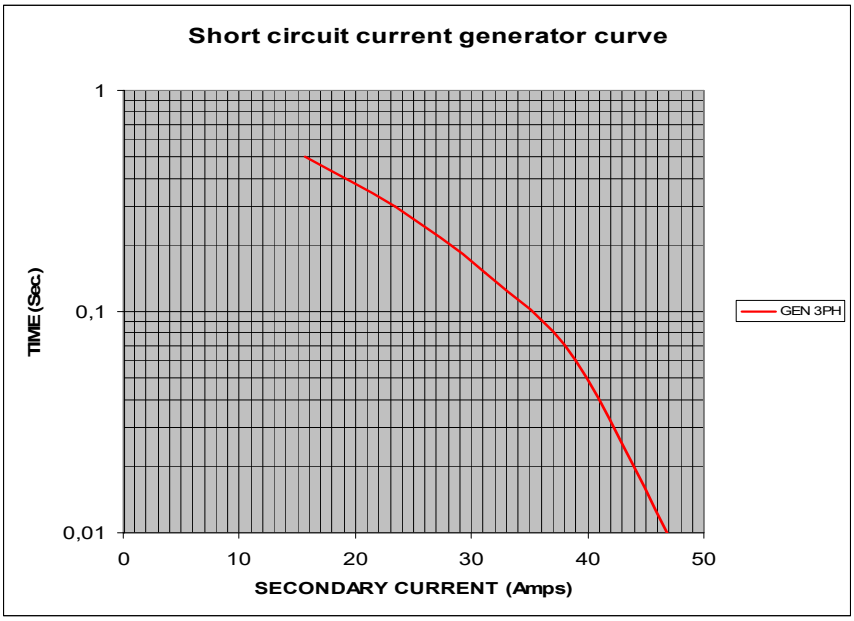


Fig. 2.9. Short circuit decrement curve in Generators

There are other factors (depending of the relay design), that can reduce the Over dimensioning value (Ktf).

- Some GE relays such as L90 (Line differential protection), G60 and SR489-Firmware revision 150.000 and up (Generator protection) have directional algorithms that improve the relay performance during CT saturation (See Fig. 5). In case of L90 there is a feature that increase the restraint multiplying the sigma value (*) (used in the adaptive restrain) by a factor of 2.5 to 5 for external faults. Based on this, we can reduce the Ktf to a value of 4 while maintaining the same reliability level (for transmission lines with bundle conductors and close to Generator Power Plants, this value could be higher). In case of G60, the differential element (the critical one) has a directional supervision that is not affected with CT saturation. In this case, the use of Ktf values as low as 8 will not present a problem.
- From the point of view of the over current time delay functions, the effect of saturation is low in transmission lines and feeders. We need to take care only in Generators and Power transformers. The problem during CT saturation is the reduction of the fault current that can provoke the no activation of the unit or longer operating times (reference 6 gives a good explanation of the phenomena) . Adding the voltage restraint available in the majority of GE relays and a pickup at least 0.5 times of the minimum fault current can minimize this risk, not being a critical condition to impose higher requirements on the CT´s. Instantaneous OC functions are not affected because the operation time (1).

(*) GE's adaptive elliptical restraint characteristic is a good approximation to the cumulative effects of various sources of error in determining phasors. Sources of error include power system noise, transients, inaccuracy in line charging current computation, current sensor gain, phase and saturation error, clock error, and asynchronous sampling. Errors that can be controlled are driven to zero by the system. For errors that cannot be controlled, all relays compute and sum the error for each source of error for each phase. The relay computes the error caused by power system noise, CT saturation, harmonics, and transients. These errors arise because power system currents are not always exactly sinusoidal. The magnitude of

these errors varies with time; for example, growing during fault conditions, switching operations, or load variations. The system treats these errors as a Gaussian distribution in the real and in the imaginary part of each phasor, with a standard deviation that is estimated from the sum of the squares of the differences between the data samples and the sine function that is used to fit them. This error has a spectrum of frequencies. Current transformer saturation is included with noise and transient error. The error for noise, harmonics, transients, and current transformer saturation called “sigma value” is computed and incorporated in the restrain algorithm.

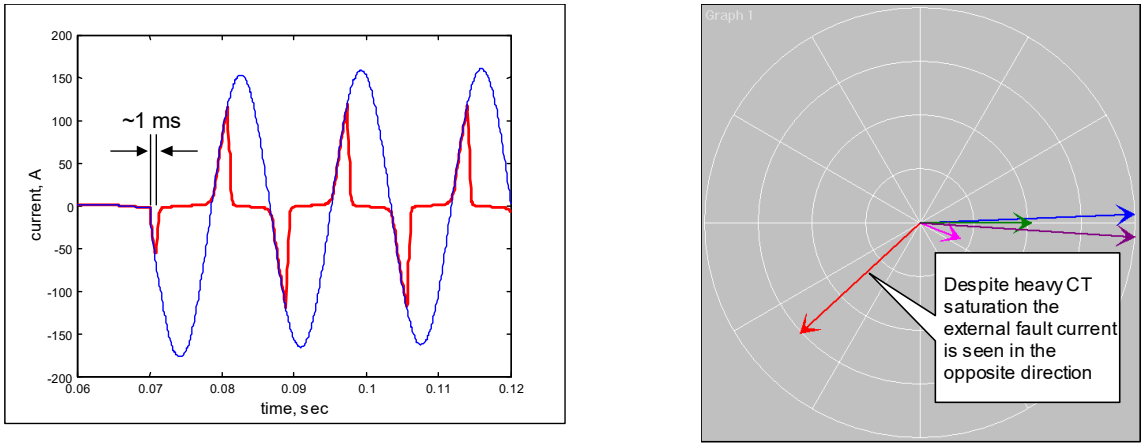


Fig 2.10. Directional algorithm in differential approach is not affected by CT saturation

APPENDIX 3

Typical X/R values

The values listed are only orientate ones. It is recommended to use the manufacturer's parameter for the specific element whenever available.

Transmission lines

Typical values of ***X/R*** ratios of distribution and transmission lines depending on their rated voltages and geometrical configuration are shown in Table 1.

TABLE 1						
Sequence	**X/R Ratios for Distribution and Transmission Lines**					
	69 kV (Avg.)	**115 kV (Avg.)**	**138 kV (Avg.)**	**230 kV (Avg.)**	**380 kV (Line Type)**	**500 kV (Line Type) (α)**
X_1/R_1	2.30	3.40	3.98	7.36	9.80 (Hor.) 9.6 (Delta)	24.3 (Hor.) 18.5 (Vert.l)
X_0/R_0	1.95	3.05	4.23	4.08	3.2 (Hor.) 3.3 (Delta)	3.5 (Hor.) 5.0 (Vert.)

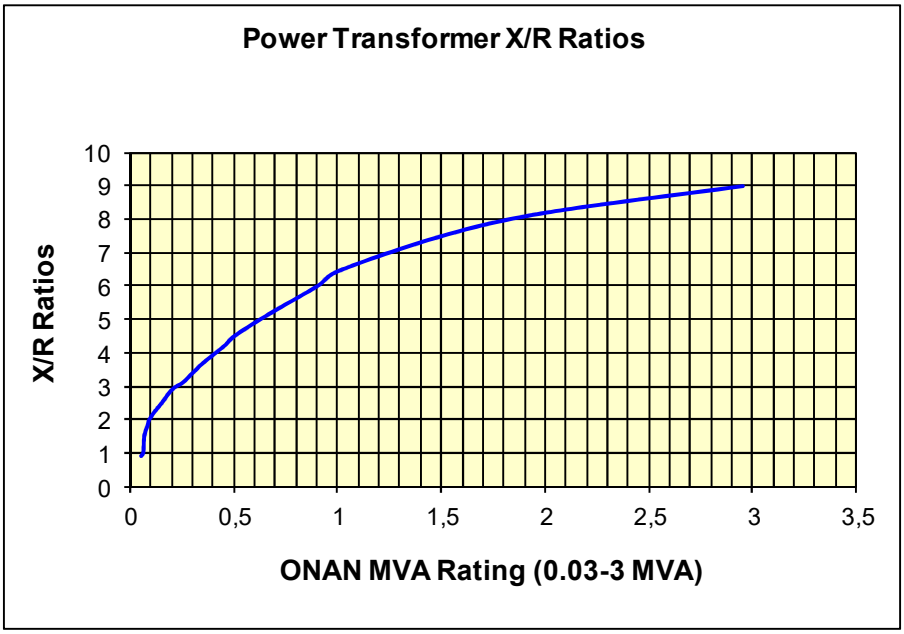
(α) Values refer for a line with bundle conductors with 4 conductors per phase

X/R values are only for the line. They do not include the source impedance X/R value. The criteria for CT dimensioning assumes that the X/R value of the particular element is the predominant one.

Generators and Power Transformers

Table 2 shows X/R ratios for generators, transformers, etc. as a function of their rated power.

TABLE 2			
X/R Ratios for Other Power System Elements			
Large Generators	**Power Transformers**	**Reactors**	**Utilities**
40-120 Typical 80	See Curve	40-120 Typical 80	15-30 (near generating plant)



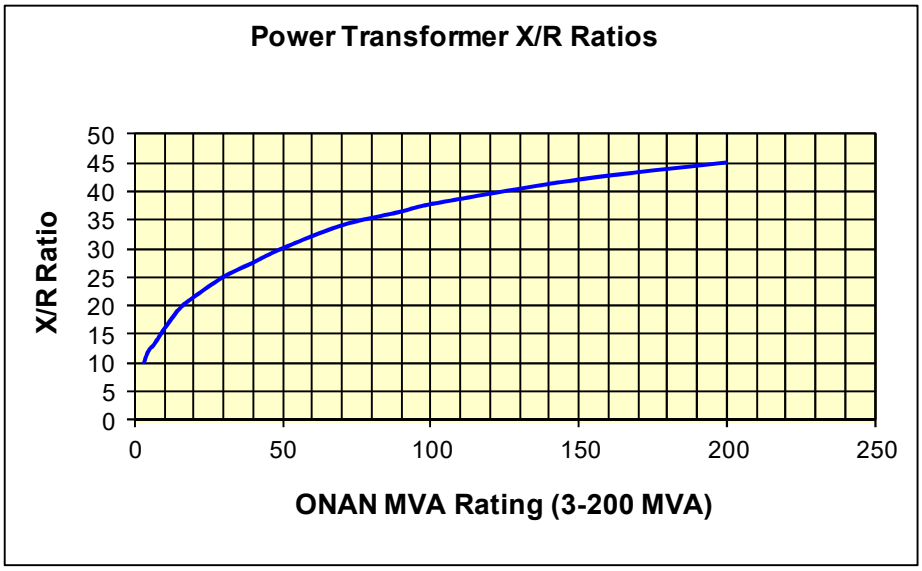


Fig. 3.1

APPENDIX 4

Criteria for CT calculation in High Impedance Relays

MIB relay

Setting calculation of MIB

a) Overall Criteria

The worst condition would be realized if the CT associated with the faulted circuit saturated completely, thus losing its ability to produce a secondary voltage, while the other CTs did not saturate at all. When a CT saturates completely, its secondary impedance approaches the secondary winding resistance, provided the secondary leakage reactance is negligible. The CTs in the infeeding circuits would then be unassisted by the fault CT and would have to produce enough voltage to force their secondary currents through their own winding and leads, as well as the windings and leads of the CT associated with the faulted circuit. As a result, a voltage will be developed across the junction points and hence across the MIB relay. The magnitude of this voltage will simply be equal to the product of the total resistance in the CT loop circuit and the total fault current in secondary amperes, that is,

$$V_S = (I_F / N)\,(R_S + P * R_L) \qquad (1)$$

V_S = Maximum possible voltage across the MIB relay for a fault

R_S = DC Resistance of fault CT Secondary Winding = 1.074 Ω

R_L = Single conductor DC Resistance of the current circuit cable

= 0.216 Ω for 10AWG 200' long cable

P = 1.0 (for 3Ø fault)

I_F = Maximum external fault current = 18,100 Amps

N = CT Ratio

For the conditions in question, this voltage V_S, is the maximum voltage that could possible be developed across the MIB relay. Obviously, the CT in the faulted circuit will not lose all of its ability to produce an assisting voltage, and the CTs in the infeeding circuit may tend to saturate to some degree. In practice, the voltage developed across the relay will be something less that calculated from equation above. The effect of CT saturation is accounted for by the CT performance factor, K, used in the equation for calculating the actual voltage equivalent to current setting.

Now consider the effect of an internal fault. In this case, all of the infeeding CTs will be operating into the high impedance PVD in parallel with any idle CTs. The voltage developed across the junction points will now approach the open circuit secondary voltage that the CTs can produce. Even for a moderate internal fault, this voltage will be in excess of the value calculated for the maximum external fault as described above. Therefore, the high impedance current sensing (across the stabilizing resistor), can be set with a pickup setting

high enough so that it will not operate as the result of the maximum external fault, but will still pickup for moderate and even slight internal faults. Consequently, the relay will be selective between internal and external faults or load flow.
The actual equation for calculating the pickup setting, taking CT performance and margin into account, is as follows:

$$I_R = 1.6\,(V_S / R_E) \qquad (2)$$

I_R = Pickup Setting of the 87 unit

1.6 = Margin factor

R_E = Stabilizing resistance (2000 Ohms)

b) Setting Procedure

<u>CT Ratio / Accuracy Class</u> – 4000/5, C200
<u>Available 3Ø fault current</u> – 18,100 Amps (Bus B)

(1) Applying Voltage calculation:

$$V_S = (I_F / N)\,(R_S + P{*}R_L)$$

V_S = Maximum possible voltage across the MIB relay for a fault

R_S = DC Resistance of fault CT Secondary Winding = 1.074

R_L = Single conductor DC Resistance of the current circuit cable

= 0.216 for 10AWG 200' long cable

P = 1.0 (for 3Ø fault)

I_F = Maximum external fault current = 18,100 Amps

N = CT Ratio

$$V_S = [18{,}100/800]\,[1.074 + 1(.216)] = 29.2 \text{ Volts}$$

(2) Applying Current Calculation:

$$I_R = 1.6\,(V_S / R_E) \qquad \text{(MIB pickup setting equation)}$$

I_R = Pickup Setting of the 87 unit

1.6 = Margin factor

R_E = Stabilizing resistance (2000)

$$I_R = 1.6\,(29.2 / 2000)$$

$$I_R = 0.0233\text{A} \sim 25\text{mA}$$

Important remark: This value is the minimum safe setting. Higher settings will provide more safety margin, but will result in somewhat reduced sensitivity.

c) Complementary verification to know if there is sufficient short circuit current to activate the MIB relay

(3) Minimum fault to trip voltage element

$$I_{min} = [\, nI + I_R + I_1] * N$$

I_{min} = Minimum rms sym. Internal fault current required to trip 87

n = Number of CTs (13)

I = Secondary excitation current of individual CT at a voltage equal pickup level of 87

I_R = Current in the relay at pickup level

I_1 = Current in the MOV unit at 87 pickup level

N = CT Ratio

The sensitivity of the relay voltage element is

$$I_{min} = [(13)(I) + 0.025 + I_1]\ 800 = \text{XXX Amps}$$

Note: Point 3 can be ignored if there is sufficient short circuit current during internal faults.

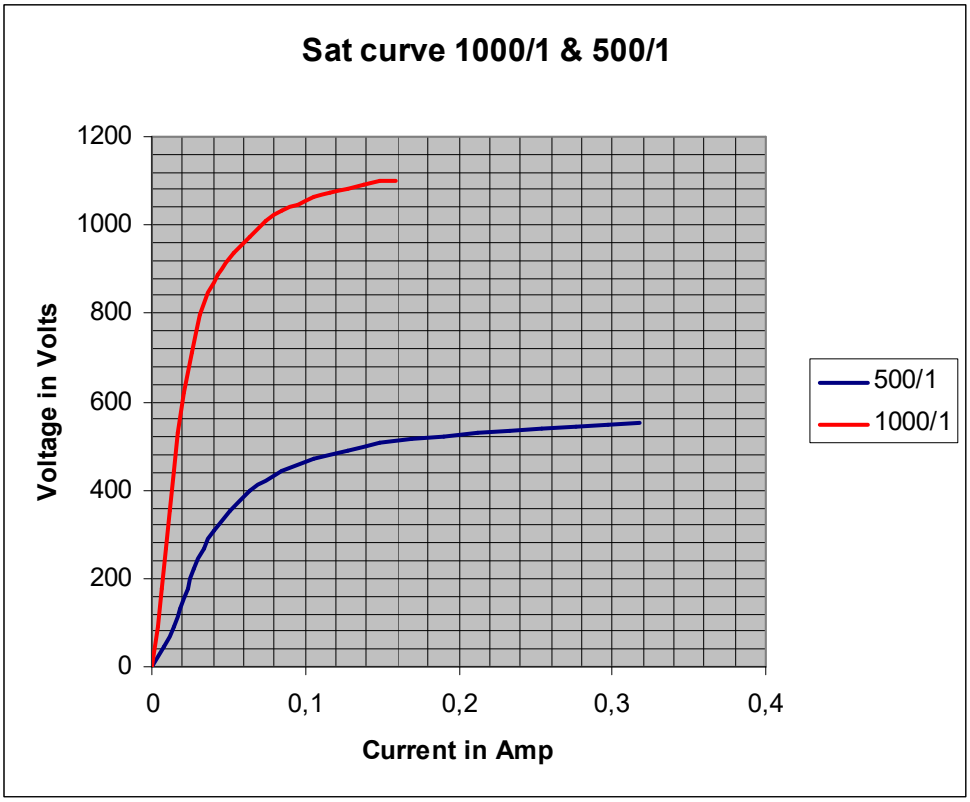


Fig. 4.1. Example of CT saturation curve

From the above calculation we see that it is possible to use a lower CT class (lower saturation voltage). The preceding steps can be repeated for various CTs in order to optimize CT selection.

Note: The reference (7) shows in detail all the calculation process for MIB High Impedance Differential relays

BUS1000

For external faults, the secondary circuit of a fully saturated line CT can be represented by its total DC loop resistance only, i.e., with negligible reactance

For internal faults, the secondary circuit of an unloaded line CT can be represented by relative large magnetising impedance, mainly reactive with large (L/R) time constant

This burden includes: the secondary winding resistance, the pilot-wire loop resistance and the resistance of any additional apparatus. The burden of the auxiliary CT´s can normally be disregarded

Line CT knee-point voltage requirement

The line and auxiliary CT´s must have knee-point voltages capable of driving the current 2In through the differential circuit. Note that this value is considerable higher than the minimum operating current that depends on the K value according with the table enclosed:

K	Sensitivity in A (In=1A)
0.5	500
0.6	0.25
0.7	0.33
0.8	0.5

For that, we are assuming a conservative position.

i.e., the relay input voltage must be equal or exceed to

Vk =N x 2In x RE

In is based on the global CT ratio. For the individual CT´s, this value needs to be adjusted according with

N = Individual CT ratio/Global CT ratio

As RE = 250 Ohm and In = 1 A

Vk = 500 x N volts on 1 A side

If primary is 5 A, then voltage values need to be corrected with the corresponding CT ratio. They will be lower that the calculates for 1 A.

Note: Values of Rmax at 5A nominal sides must be kept according with the following criteria (values for 1A are given in the manual)

$Rmax < R_E * 2 K/(1-K)$

If we refers all to 5 A side then R_E = 250/25 = 10 Ohm (on 5 side)

With these values we can produce the following table

K	Rmax (limit value)
0.5	20 Ohm
0.6	30 Ohm
0.7	46.7 Ohm
0.8	80 Ohm

APPENDIX 5

Calculation Examples

Calculation of CT for L90.

Parameters

CT ratio = 600/1 in 145 kV with Knee point (Vkp) of 95 (Rct + 2.5) = 465.5 Volts (500 Volt approx with 10 A exc. Current). Class 5P10.

Rct = 2.4 Ohm. We will assume total burden (Relay + leads) = 1.2 Ohms (RL=1. (200m of 4mm2 copper cable); Rburden=0.2

Total Burden = 3.6 Ohms.

1. Internal faults (F1). We will assume a source with short circuit current of 50,000 A.

INPUT PARAMETERS:		ENTER:	
Inverse of sat. curve slope =	S =	20	---
RMS voltage at 10A exc. current =	Vs =	500	volts rms
Turns ratio = n2/1=	N =	600	---
Winding resistance =	Rw =	2,400	ohms
Burden resistance =	Rb =	1,200	ohms
Burden reactance =	Xb =	0,000	ohms
System X/R ratio =	XoverR =	10,0	---
Per unit offset in primary current =	Off =	0,80	-1<Off<1
r unit remanence (based on Vs) =	λrem	0,00	---
ymmetrical primary fault current =	Ip =	50.000	amps rms

Because we have an internal fault, the most important criteria is assure to have enough signal magnitude to trip the relay.

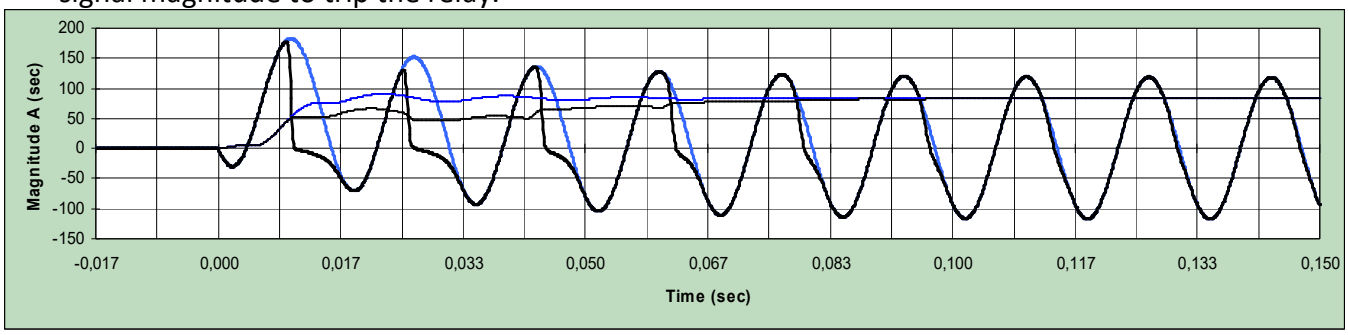


Fig. 5.1 Effective signals to the relay. CT saturated (black) and CT non saturated (Blue

Thick lines: Ideal (blue) and actual (black) secondary current in amps vs time in seconds.
Thin lines**:** Ideal (blue) and actual (black) secondary current extracted fundamental rms value, using a simple DFT with a one-cycle window.

Note: The calculation has been made using the IEEE Power System Relaying Committee publication, "CT Saturation Theory and Calculator",

From Fig. 5.1, we can see that in the worst circumstance we will have enough signal magnitude in the local relay to trip, but including with a total CT saturation we will have the signal from the remote end to trip the relay during internal faults.

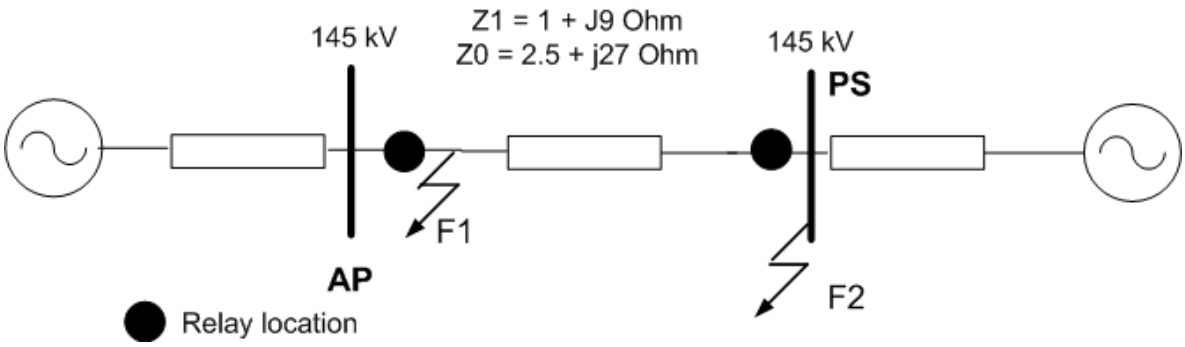


Figure 9. Example of fault location

2. External faults (F2). In external faults the criteria are to assure a non tripping action during external faults (through current). For that, the important thing is to evaluate if the relay will saturate when the through current is circulating through it.

   We will assume a typical line of 30 Km in length. The typical line impedance is 0.3 ohms/km. For that, the impedance will be = 9 Ohms. With this impedance, the 50,000 A became to 7,850 A. We will use 8,000 A.

We will use the Over dimensioning factor as 5 for voltages up to 220 kV and 6 for voltages over 220 kV.

Vsat = 3.6 * 5 * 8000/600 = 240 Volts is the minimum saturation voltage required. This is under the knee point (465.5 V)

Using 5P10 CT, the minimum Power saturation free operation is given by the equation:

$$((240/10)/1 – 2.4) * 1^2 = 21.6 \text{ VA}$$

The CTs of 30 VA are suitable for this application.

Note: The short circuit value (50,000 A) is the maximum one that normally is used for design in 400 kV. In any case, the main factor that limits the short circuit current is the line impedance.

Other calculation examples can be found in the references (6) & (7)

APPENDIX 6

Importance of having similar CT characteristics in a Generator Differential protection

As we mentioned in the Appendix 2, there is very important the correct application of the Over dimensioning factor in Generator Application and in differential algorithms.

Generator Differential algorithms in general use the percentage restrain where the restrain signal is the average of the currents from neutral and terminal sides or the maximum of the two currents. In most relays is the only criteria used.

One important factor in CT application in generators is that very often the neutral side of the generator has low-voltage type of current transformers for mounting around the cable, while the current transformers on the terminal side of the generator are of the medium voltage type for 3.6kV or 7.2kV or 12kV depending upon the service voltage. In other words, the CTs are not identical in construction and they will not have the same transient response.

System Parameters

System X/R ratio	XoverR =	20	---
Per unit offset in primary current	Off =	-1	-1<0<1
Symmetrical primary fault current	Ip =	3500	amps rms

	CT 1 Parameters			CT 2 Parameters		
Inverse of sat. curve slope	1/S1 =	22	---	1/S2 =	22	---
RMS voltage at 10A exc. Current	Vs1 =	400	volts rms	Vs2 =	200	volts rms
Turns ratio	N1 =	240	---			
Winding resistance	Rw1 =	4	ohms	Rw2 =	4	ohms
Burden resistance	Rb1 =	0	ohms	Rb2 =	0,2	ohms
Burden reactance	Xb1 =	2	ohms	Xb2 =	2	ohms
Per unit remanence	Irem1 =	0	---	Irem2 =	0	

Relay Settings

Minimum Pickup	Minpu	0,05
Slope1	S1 =	20,00%
Slope 2	S2 =	40,00%

Figure 6.1. Parameters of two CTs with the same ratio, but different Vkp point

Calculations has been made using a variant of the spreadsheet from the IEEE Power System Relaying Committee publication, “CT Saturation Theory and Calculator” (5).

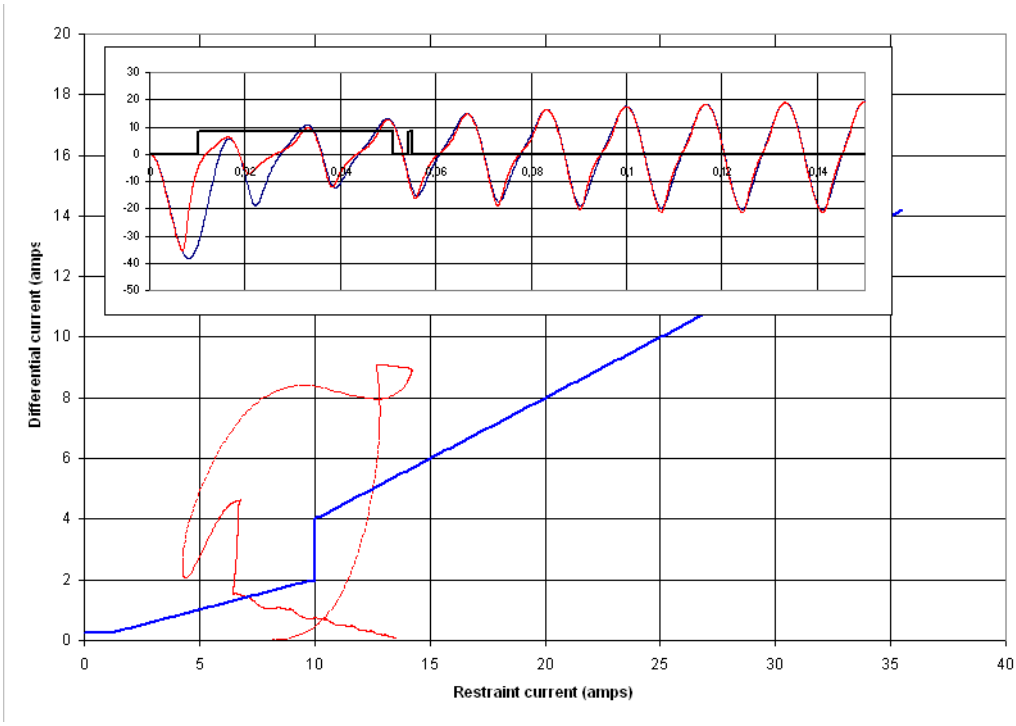


Figure 6.2. Unequal CT saturation on CTs with equal ratio and different Vkp. Differential operates

If we put CTs with equal ratio, equal Vkp, but different burden, the performance will be as the figure 6.3

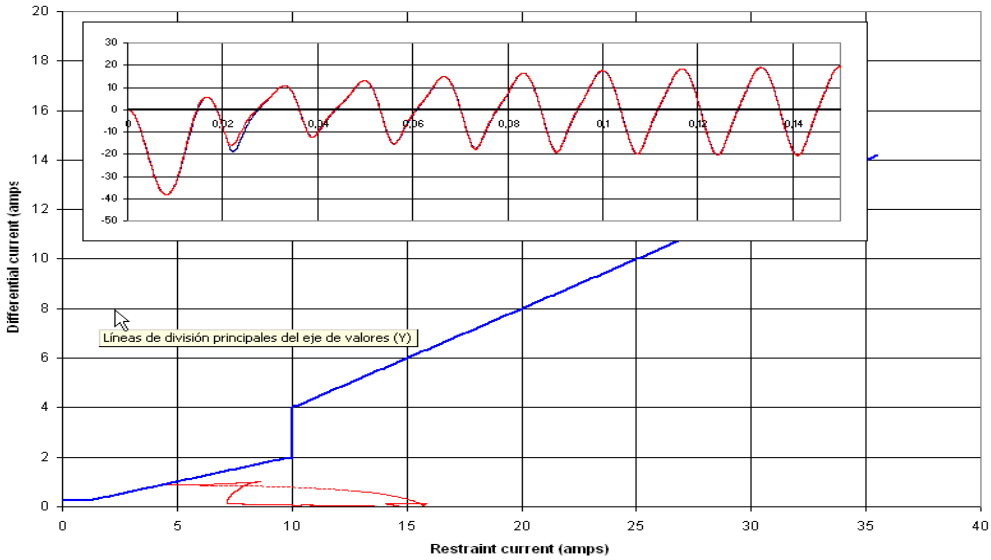


Figure 6.3. Unequal saturation on CTs with equal ratio and Vkp, but different burden.

From Figures 6.2 and 6.3 we can see the importance of having the same Vkp point. In Fig 6.2, the cause of the differential activation was the different Vkp point (both CTs are with the same ratio). Looking the Figure 6.3, we can observe that the differential algorithm was near to cause a trip (in this case both CTs are identical. Same ratio and same Vkp). In this last case the only difference was the burden (One Ct has 0.2 ohms of additional burden). The difference in burden is very frequently because we can not assure 100% that the length of the wiring to one side will be identical to the other side. Frequently the burdens are different and this is the reason because a convenient over dimensioning factor is recommended when a differential protection is applied in Generators and in Transformers (According to Appendix 2, an over dimensioning factor of 15 is recommended to avoid a trip during external faults that could cause CT saturation).

Fortunately, in the GE relays we have other algorithms (directional) that are not affected by the saturation and complement the differential algorithm when a saturation condition is detected. This allows a reliable operation, and in certain way allows to soften the CT requirements compared with other relays where the only condition to trip is the well-known percentage restraint algorithm. Some examples of the relays that incorporates the directional algorithm are B30, B90, G60, 889, SR489, T60/T35 (f/w 7.40 and up), 845, M60, 869, B90 and SR489.Using the Ktf = 15, we can obtain that the CTs need a Vkp of 879 Volts for the fault current and ratio values of Figure 6.1. Recalculating with the new parameters, the response of the algorithm is shown in Fig. 6.4.

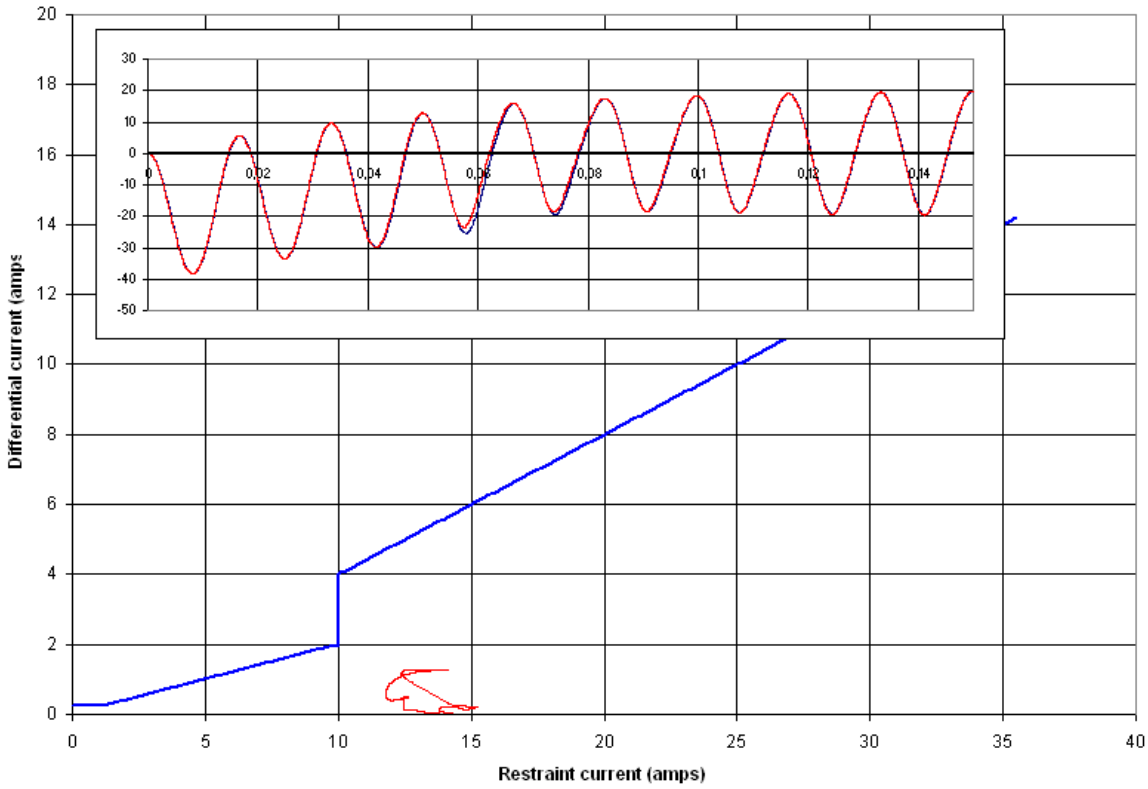


Figure 6.4. CTs correctly dimensioned. Equal ratio and Vkp and different burden

We can observe that the operating point is in the restraint area.

APPENDIX 7

CT Equivalences between IEC and ANSI Standards

There are different standards around the world, but the most common used are the IEEE C57.13 (common in America) and the IEC 60044-1 (widely used around the world). Both standards are equivalent. In the Table 1, we can observe the equivalent for the most common types used.

The criteria for IEEE relaying Class is for the CT to develop a voltage at its terminals at 20 times rated current and not exceed 10% of error at this fault level. This terminal voltage must consider the internal volt-drop of the CT winding. The total CT voltage can be estimated

$$required\ voltage = (z_s + z_b) * I_{fs} \qquad (7.1)$$

$z_s =$ Secondary CT resistance

$z_b =$ Burden

$I_{f20} =$ Secondary current (short circuit current = 20 times the nominal)

This is a simplified equation and it is adequate for estimation purposes, if the error current will be the exciting current at the required voltage. These values can be read from the CT saturation curve normally supply by the manufacturer.

Taking the exciting current as a percentage of the secondary fault current, which for a 5 A nominal secondary at 20 times fault will produce 100 A fault current in the secondary, therefore 10% would be the voltage at or less than an exciting current of 10 A.

$$I_{mag} / ((I_{f20}) * 100\% \qquad (7.2)$$

The IEC standard has several classes (P, TPY, TPZ, TPX), being the most common 2 classes, 5P and 10P. The “P” means “protective”. One can easily convert and IEC class into an equivalent IEEE class by taking the equivalent ohmic burden value and inserting into eq. 7.1. If the burden is something other than given in Table 1, the ohmic value can be calculated as follows:

$$ohms = \left(VA / I_{\text{sec}}^{2}\right) \tag{7.3}$$

The IEEE standard burdens for relaying are 1, 2, 4, and 8 ohms, all with an impedance angle of 60º. The voltage standard classifications are 100, 200, 400, and 800. Because the error at impedance angles close to 0º is in the order of 5% (the standard specify 10% but with impedance angle of 60º). IEEE classes “C” and “T” can be considered equivalent to the 5P class in IEC.

Table 1 Equivalent CT accuracy Ratings

IEEE C57.13	IEC 60044-1
C100	25 VA 5P20
C200	50 VA 5P20
C400	100 VA 5P20
C800	200 VA 5P20

APPENDIX 8

Conversion in class TPX or equivalent 5P

IEC rules provide a composite error in % connected to a ratio rated current (IN) / External load set in VA at IN.

Example: CT 1000 / 5 A - 50 VA 5 P 20.

This equation indicates that the composite error must be less than 5% for a 20In primary symmetric current with an external secondary load equal to 2 ohms (50VA at In). If the secondary resistance RCT is known, the magnetic FEM created during the fault current at 20In could be easily calculated. If the error is 5%(=5A) at this FEM, the active point is after the knee point saturation.

By convention the knee point voltage Vkp is at 80% of this value. To switch from a class 5P (IEC) and a class X (BS), the following relation is used :

$$V_k = 0.8\ x \left[\frac{VA\ xALF}{I_n} + (R_{CT}\ x\ ALF\ x\ I_n)\right]$$

with

VA = Rated burden in volts-amps,

ALF = Accuracy limit Coefficient,

In = Rated secondary current CT.

APPENDIX 9

Questions and answers

The purpose of this section is to provide additional references for some special application cases in order to illustrate better the use of the over dimensioning factor in CT dimensioning.

1. **Case 1**

Question:

The application is line differential (Overhead line+ Cables). As per GE recommendations, the

Vk= Ktf * If * (Rct+ RL+ Rp) will be used. The switch board is 25kA rated.

What is the recommended Ktf factor which can be considered for OHL(2100m) cable (1350 m) combination?. As per GE for Ktf =5 to 6 for EHV lines?.

Answer:

Cables introduces more resistance, so the X/R ratio decreases and the transient is less critical. Because the line is short (2100 m + 1350m), then the source becomes important. If the source is a Power transformer, then the total X/R will be high. In this case use a high Ktf and no reduction factor. If the source is a transmission line, then you can maintain Ktf = 5 (this value can be corrected according to the voltage level).

1. **Case 2**

Question:

CT Vk requirement for B30 seems to be higher as compared to that of a high impedance busbar protection. Our application involves replacing existing high impedance b/b protection relay on a 600m length of cable with B30.

Answer:

B30 is low impedance relay. High impedance schemes work in the saturation region and low impedance in the linear region. The CT requirements are relative. The CT requirements on B30 and B90 are based mainly on the differential algorithm, but in both cases, we have additionally the directional unit (directional is practically non- affected by CT saturation) that brings additional stability and therefore lower CT requirement in the real circumstances. As we can see, the document is for general application and addressed to be in the safest position. Cases must be analysed in depth and engineering judgment must be applied in the determination of the final solution.

This does not mean that the CTs will not be practical for B30.The directional algorithm compensates the possible poor CT performance, but a complete analysis using the CT characteristics must be carried out, to ensure that the CTs will not saturate completely at the beginning of an external fault, to allow the activation of the directional function by the saturation detector (B30 can discriminate for saturation times higher than 2.5 ms at 50 Hz or 2 ms at 60Hz) (5).

2. **Case 3**

Question:

What are the CT requirements for motor protection?

Answer:

CT requirements in large motors are determined mainly by the requirement for differential protection. In these cases, the criteria for transformer differential can be applied. Note that long starting time could saturate the CTs and cause a trip from the differential unit. In case of medium and small sized motors (where the differential protection is not applied), the criteria used for Overcurrent relays (Pages 9 and 10) is normally applied. The only risk is to have unequal CT saturation in the three phases. In this situation it will appear a “false zero sequence current” that could cause a false trip during the motor starting when the residual current is used to protect the motor against phase-to-ground faults. One countermeasure could be to apply a time delay that is only active during the motor starting (with this, we will avoid oversizing the CTs). The other alternative is to use a ground CT, to have the ground current as the signal available to protect the motor against phase-to-ground faults. In any

case, it will be the engineer's judgement who will decide the best option. One interesting guide to select the CTs for motor protection for the GE Multilin relays is given in the reference (6).

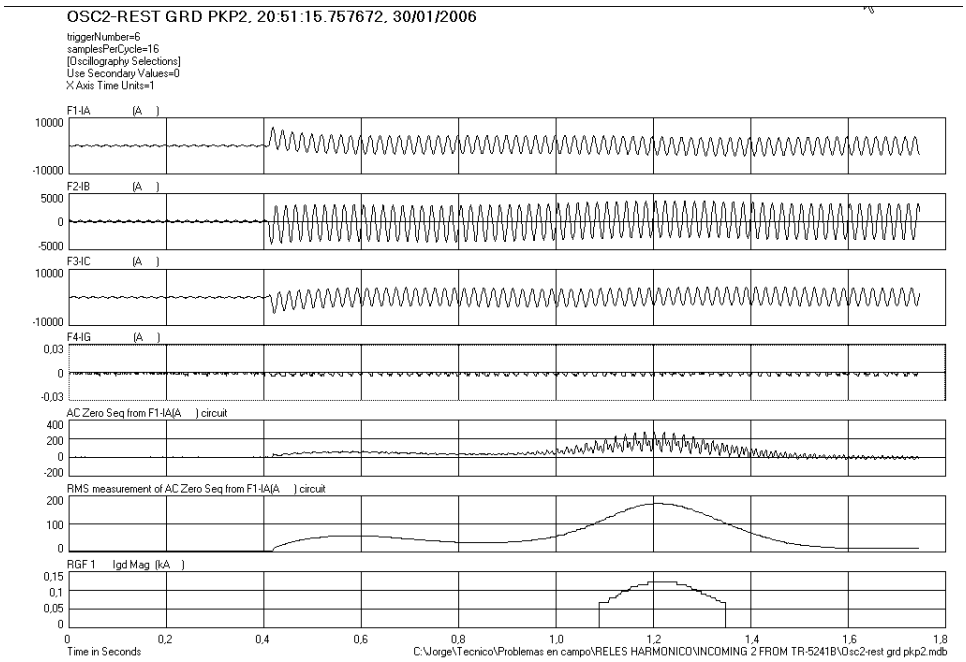


Fig. 9.1 During motor starting CTs saturate unequally producing a "false" zero sequence current

3. Case 4

Question:

Are there any other specifications for cores that are used for Transformer Winding Low Impedance Restricted Earth-Fault Protection?

Answer:

Depending of the relay used the CT requirements can be restrictive.

In case of the SR745 relay, the issue of mal operation due to heavy external faults resulting in CT saturation is handled by a programmable timer. The timer provides the necessary delay for the external fault to be cleared by the appropriate external protection with the added benefit that if the RGF element remains picked up after the timer expires, the 745 operates and clears the fault. This approach provides backup protection. Since the RGF

element is targeted at detecting low magnitude internal winding fault currents, the time delay for internal faults is of little consequence, since sensitivity and security are the critical parameters. In this case, if timer is not being used, CT requirements criteria is like the one used for phase differential protection, considering the current magnitude.

In case of T60 relay, restraint signal is memorized with decay to half of the initial value after 15 cycles. This feature allows to reduce the CT requirements at values that could be up to 50% less than ones used for phase differential unit. Special care must be have in case of industrial loads (motors), because the transient caused by the starting. In this case, use a more conservative criterion avoiding any CT under sizing.

4. **Case 5**

Question:

I have a line of 10 Km length at 145 kV, through short circuit current of 18,446 RMS primary amperes, X/R ratio of 20. My CT ratios are 400/1 at one end and 2000/1 at the other end. The 400/1 CT characteristics is as follows:

CT Ratio: 400/1

CT res: 2.2 Ohm

CT Burden: 1 Ohm

CT saturation curve: See the Figure 9.2

I have installed L90 at both ends of the line

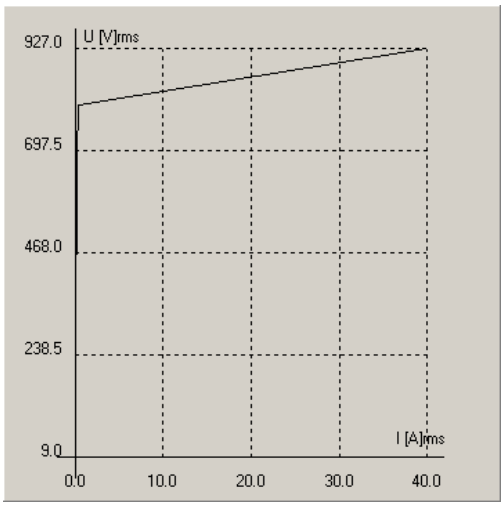


Figure 9.2. 400/1 CT saturation curve

Will the L90 performance be correct under any operation circumstance?

Answer:

The answer is not that simple, because there are several aspects that require analysis and verification.

When a CT is selected, it is important to follow the rule “start building the house from the basement, not from the ceiling”. There is a tendency to choose a CT without first determining where the CT will be installed, which element it will protect and what will be the functions used in protection (in other words, to start building the house from the ceiling).

We have seen that the differential functions are very sensitive to the CT performance and therefore, it is important first to calculate the CT. In this case, also we need to consider that the criteria used for the present document for CT dimensioning has been made based on equal CT ratios at both ends

Because in this case, the CT has been already selected, we will analyze the performance, the minimum settings that need to be applied and the complementary measures.

Step 1: To verify the L90 response assuming CT saturation in the 400/1 CT and no saturation in the 2000/1 CT.

To analyze the performance of the algorithm we will verify first the CT performance using the tool from reference (5) and the L90 differential equations.

Keep in mind that the 400/1 Ct´s will carry on 18,446/400 = 46.115 times the nominal current during external faults. This is an unusual case and a critical one

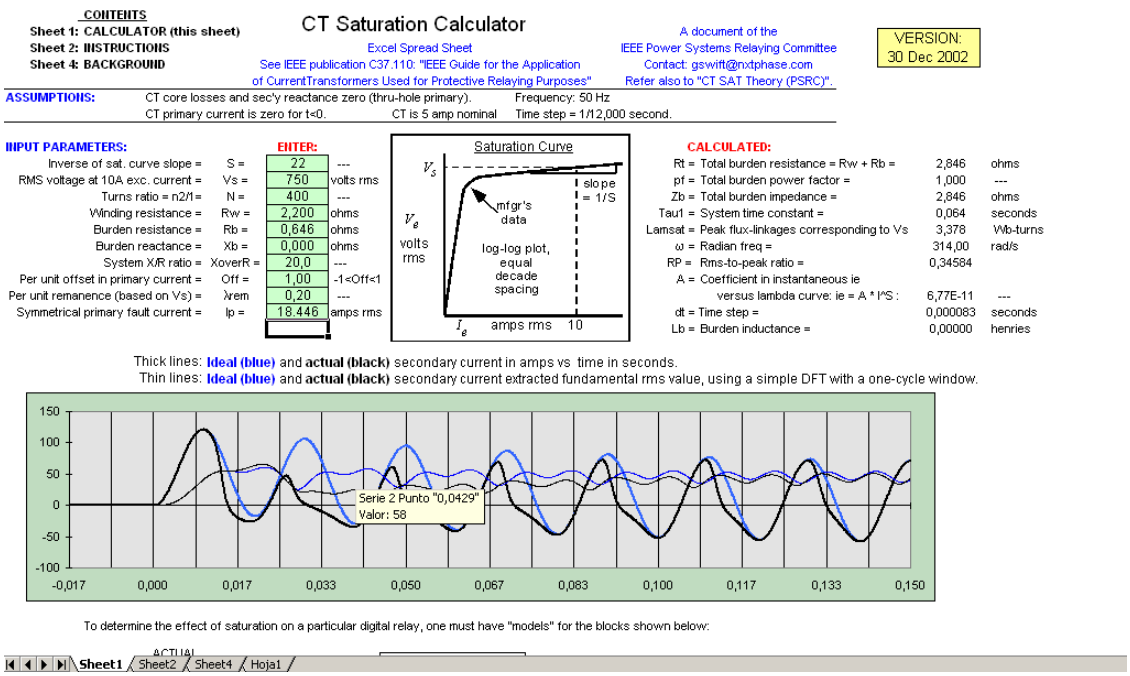


Figure 9.3. CT saturation on 400/1 CT (black). No saturation on the 2000/1 CT (blue)

From the above curve, we have in the worst case:

ILocal = 58 A (RMS secondary value with DC Offset. No saturation is assumed)

Irem = 21 A (RMS secondary with DC offset and CT saturated)

The equation for L90 is as follows:

$(IDIFF)^2 = |I\_L + (-I\_R)|^2$

$(Irest)^2 = (2S_1^2 |I\_L|^2) + (2S_1^2 |I\_R|^2) + 2P^2 + \sigma$

The criteria for tripping will be:

$(IDIFF)^2/(Irest)^2 > 1$ trip

where:

I_L = Local current

I_R = Remote current

P = Pickup value

S_1 = Slope

σ = Factor that consider the CT saturation error (We will assume equal to zero for external faults as the worst case and we will include it for internal faults)

To have equal Pickup values, we will assume 0.2 p.u. in the 2000/1 CT side, that is equal to 1.0 p.u. in the 400/1 side.

With $S_1 = 0.4$ $(IDIFF)^2/(Irest)^2 = 1369/1219 = 1.123 > 1$, then Trip

With $S_1 = 0.5$ $(IDIFF)^2/(Irest)^2 = 1369/1904 = 0.719 < 1$, then No trip

We have a situation where we need a restraint higher than 50% For that, we will evaluate the performance for external and internal faults using a higher restraint

Step 2: Complementary verification using a dynamic modelling of the line

To have a better view of the situation, we will proceed to do a network simulation using the EMPT/ATP software, simulating and approach of the L90 algorithm.

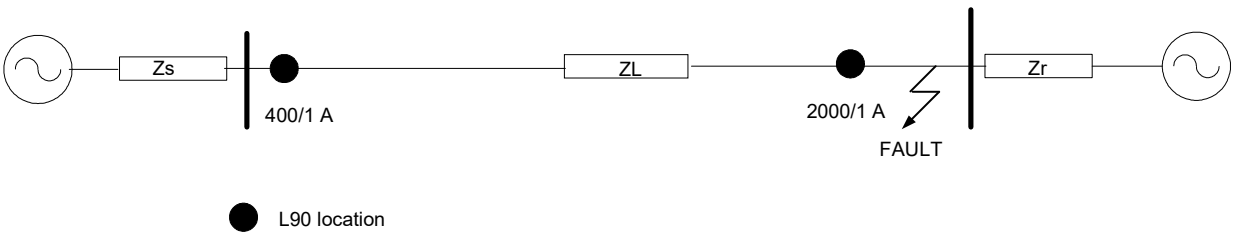
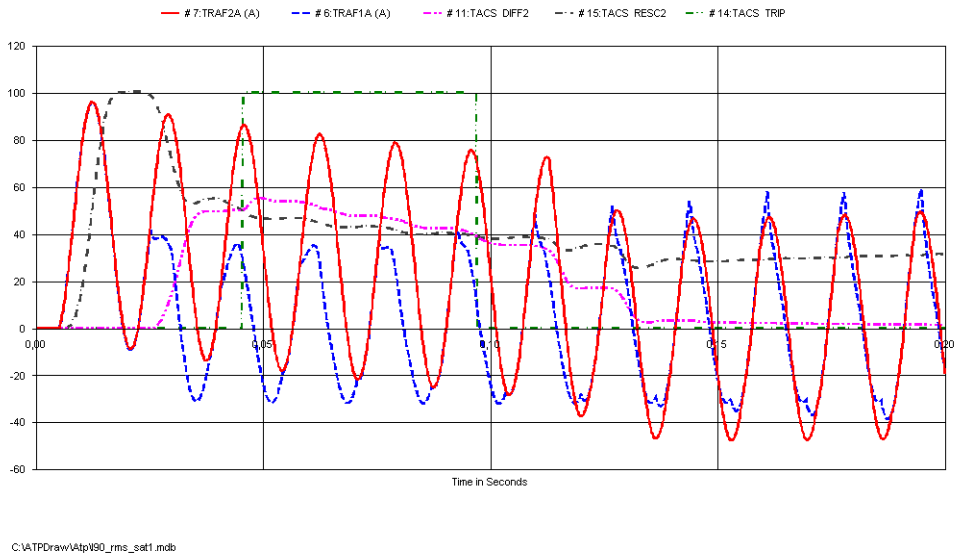


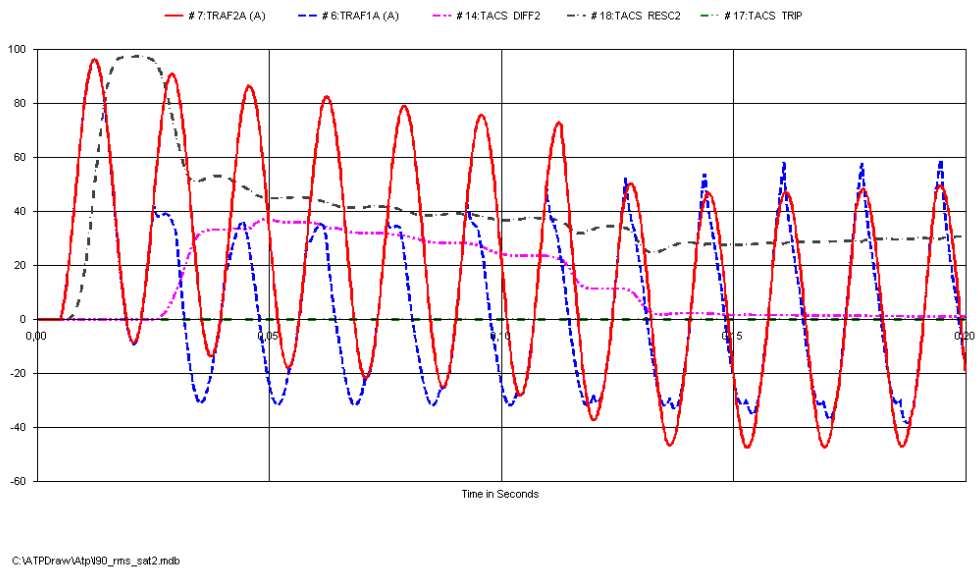
Figure 9.4. System analyzed

Case 1: External fault with CT saturation at only one end and Slope setting of 50%



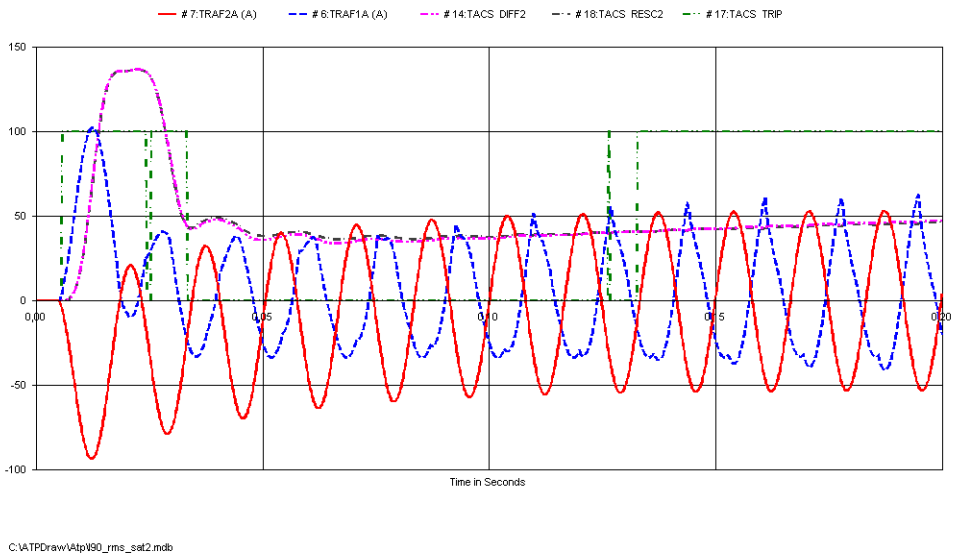
Comments: We can observe a relay trip after 3 cycles of the fault

Case 2: External fault with CT saturation at only one end and Slope setting of 60%



Comments: Relay does not trip

Case 3: Internal fault with CT saturation at only one end and Slope setting of 85%



Comments: Relay trips at a limit situation. It is recommended to seal-in the trip for at least 7 cycles.

As a conclusion, we can assure a correct performance during internal and external faults with slopes between60% to 85% for S2, being the range of 60-70% the recommended value.

Important Note: The scales for the AC currents and for the RMS values of Differential (DIFF2) and Restraint (RESC2) are not the same. In the figures we have included together only to clarify the relay performance.

Conclusions:

1. CTs of 400/1 are certainly at the limit and a high slope for a correct operation is needed.
2. It is strongly recommended to try to use the same CT ratios at both ends of the line because the length is short and the effect of DC transients is worst on short lines close to generation points than for relative long lines.

5. Case 6

Problem reported

After the successful execution of open circuit and short circuit testing for Generator Protection Relay (Model DGP) installed on a 25 MW Gas Turbine, during energization of the

25 MVA transformer (See the Figure 8.5) by closing a 33-kV transmission line, gas turbine got tripped indicating differential fault on phase-C (87C) on DGP.

After the analysis made based on the record extracted from DGP, it was confirmed that the operation occurred due to severe saturation on all three phases used for Differential Protection.

To avoid such false trips in the future, we suggested three solutions

1. The best is to change the CT´s for another one more suitable (more power). In the figure we can see that the actual CT´s are under-dimensioned. Following the criteria described in the present document, for DGP are needed CT´s with a power of 35 VA instead the 15 VA installed
2. The immediate solution is to raise the setting of the Differential pickup to a value of 0.35 p.u, as minimum value. The inconvenience is that with this action, we desensitize the protection, and it will not offer total security, because the differential current could be higher at any time during the evolution of the energization transient
3. Add an external timer of 2 or 3 cycles (because the size of the generator, this delay is acceptable) to prevent the false trip during the evolution of the transient.
4. Other solution is to introduce resistors to get a perfect balance of the secondary's, but this needs a lot of tests to be sure that the solution works

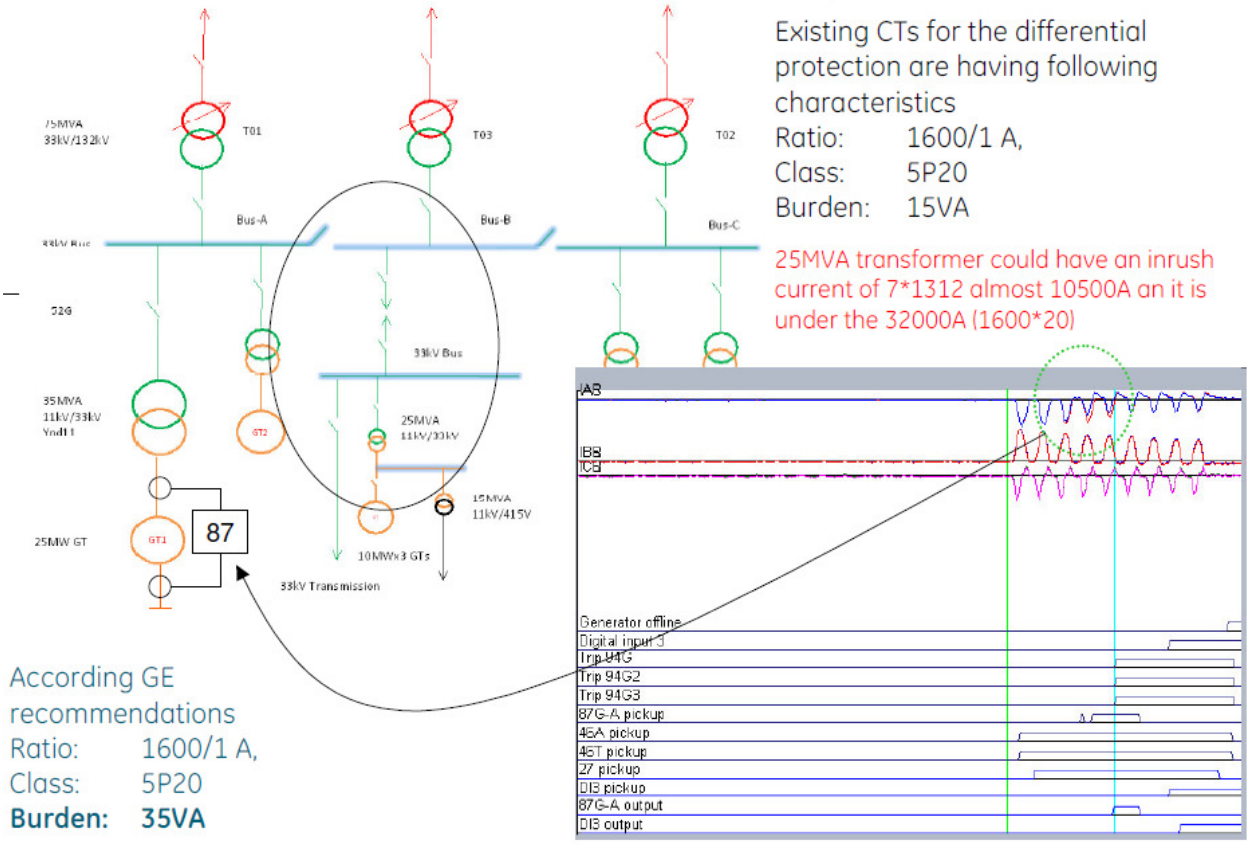


Figure 9.5. Differential Protection trip during the 25 MVA transformer energization

6. Case 6 [12]

We experienced several unwanted operation cases under the external fault.

Representatively, we introduce the most recent case as follows. The external fault (on A T/L) occurred but #61 bus protection system operated.

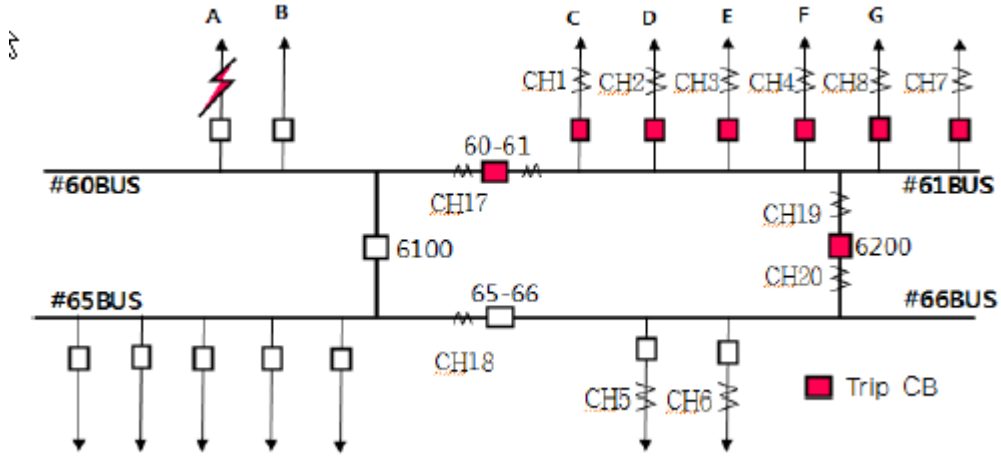


Figure 9.6 Misoperation under the external fault

The fault occurred on phase C initially and then it was evolved to 3 phase(ABC) fault after 0.5 cycle. It was found out that the current was induced on heathy phase (A and B) during initial external fault on phase C(for 0.5 cycle). So, differential relay operated due to these current.

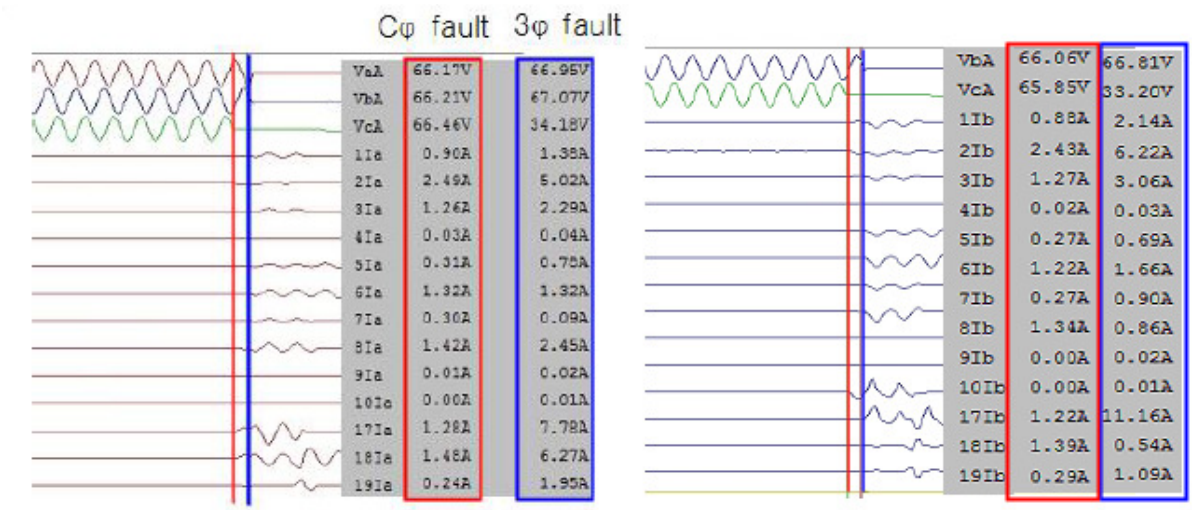


Figure 9.7 Currents on each channels(A phase(left), B phase(right))

After investigation, it was found that phenomenon, we could assume that it was resulted from “Stray flux effect” on the busbar conductor. All CTs are installed within GIS switchgear, so additional flux tends to be produced by sharp bends of the conductor at close from CTs. Current pulses are produced on the CT during stray flux condition. This erroneous induced

current on healthy phases can cause unwanted operation such as percentage differential relays.

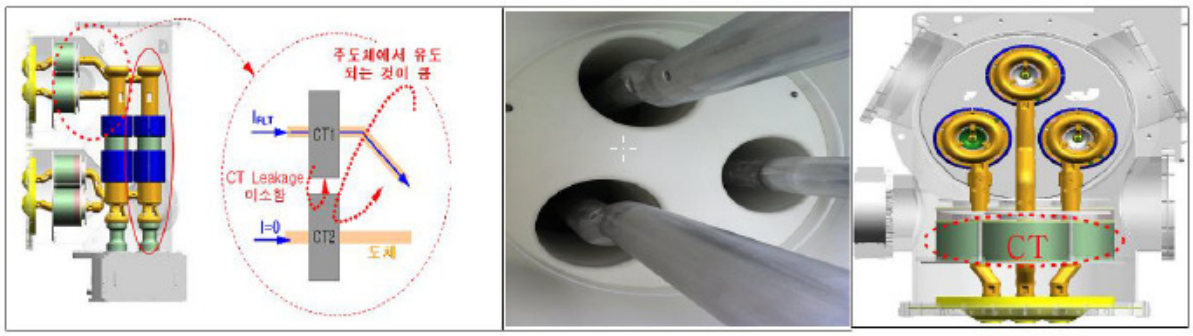


Figure 9.8 CT installations within GIS and Stray flux effect

Solution:

As a countermeasure, the minimum pickup setting value was increased and definite time delay was added (to 1 cycle) temporarily. It was adopted a user-define logic where Undervoltage fault detection per phase base elements are combined to busbar differential protection tripping logic.

APPENDIX 10

Performance of CTs and Relays at Low Frequencies [13]

CTs are designed to operate at the nominal system frequency, at lower frequency, CTs will saturate at much lower currents, this can happen even at CT nominal current. Also, there are limits of the system frequency measurements in the protective relays, which will impact the correct current magnitude estimation and therefore accuracy of the protection. And lastly, protective relays need full power cycle to measure current; power-cycle will be considerably longer at lower frequency, therefore affecting fault clearance time.

Table I

DE-RATED CT DATA

	60Hz	40Hz	20Hz	10Hz	5Hz
Relay Class	C20				
Turn ratio (N)	100:5				
Secondary winding resistance (R)	0.062Ω				
Voltage (Vs) at 10A excitation current	36.7V	24.4V	12.3V	6.1V	3.05V
Knee point Voltage (V_{knee})	26V	17.33V	8.66V	4.33V	2.16V
Saturation Voltage (V_{Sat})	36.5	24.33V	12.16V	6.08V	3.04V

a) Low frequency motor starting

Variable frequency drives (VFDs) or adjustable speed drives (ASDs) have been widely used in industry to achieve the desired mechanical output of the motor by controlling voltage and frequency of the motor supply. By controlling the supply frequency while maintaining the flux to its rated value (V/Hz constant), desired acceleration and rotational speed are achieved using the VFD.

Fig. 10.1 illustrates the current and frequency of the motor driven by the VFD.

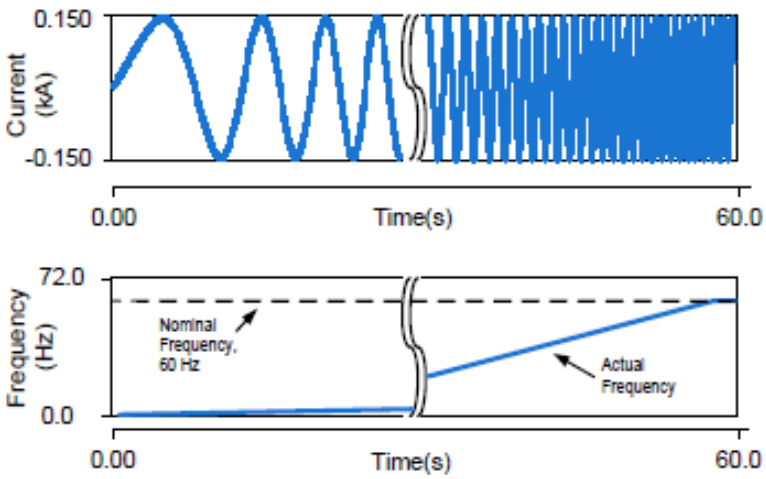


Figure 10.1 Example of Motor Starting Current and Change in Frequency

b) Back-to back motor/generator start

The back to back start-up of synchronous machines is a very suitable procedure to start smoothly a synchronous motor in pump operating mode with the help of a second synchronous generator driven by a turbine. The generator works like a variable frequency voltage supply (VFD). Both machines have to be connected trough a transmission line. Both machines are excited at standstill with a specific field current depending on the operating mode (generator or motor). The generator is then accelerated by the mechanical torque of the turbine. The voltage increases as well as the frequency at the terminals of the generator. The excited rotor of the motor follows the rotating field and when the speed is close to the synchronous one, it is ready to be synchronized with the network.

c) Impact on Protection Relays

The above procedures show that a main CT is more likely to saturate as the frequency decreases from the nominal frequency, which could impact the performance of the protection functions. Magnetic module inputs in the relay used as current transducers are also current transformers. Therefore, performance of relay current transducers at low operating frequencies is important to analyze before addressing the impact of low operating frequency at relay protection functions.

For investigation purposes, relay CT has been tested at as low as 2Hz input signal when (1) the main CT is a high-quality CT having high Vknee such that it doesn't saturate at low

operating frequencies (2) the main CT is a low-quality CT having low Vknee such that it saturates at the low operating frequencies.

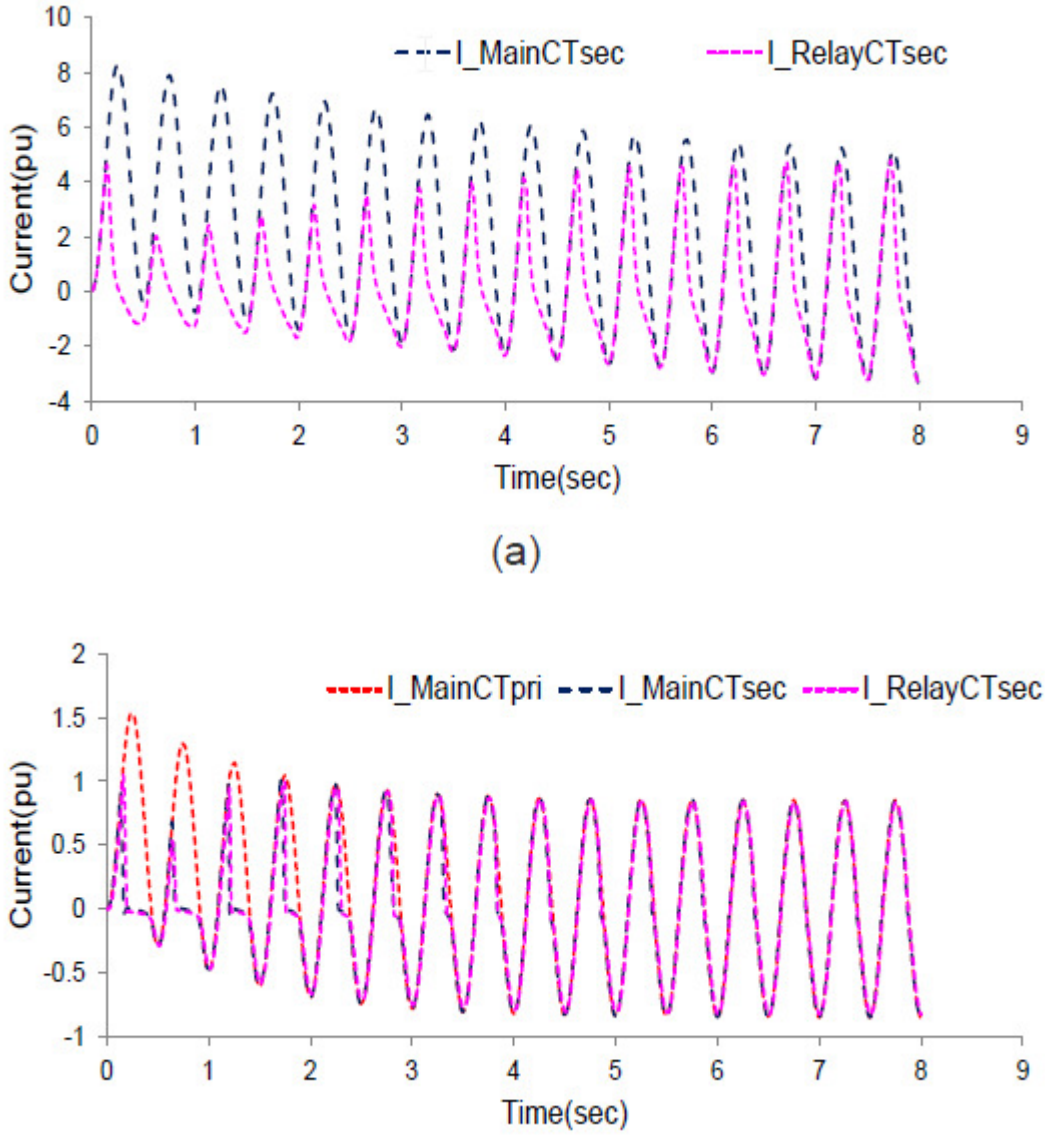


Figure 10.2 Testing of the internal current transformer of the relay when (a) input signal is transient and undistorted, (b) input signal is transient and distorted

It can be seen in Fig.10.2 (a) that when input (I_MainCTsec) to the relay is undistorted, secondary of the relay CT (I_RelayCTsec) saturates and doesn't reflect the terminal currents when operating at 2 Hz. Degree of saturation decreases as the operating frequency increases. On the contrary, when input (I_MainCTsec) to the relay is highly distorted, I_RelayCTsec properly reflects the I_MainCTsec, which means that there is no impact on the

relay CT since input to the relay is saturated and magnitude is significantly small as compared to the undistorted current (I_MainCTpri), as shown in Figure 10.2(b).

Multifunctional protection relays experience various challenges and issues when applied to low frequency input signals. Today's relays not only offer protection but incorporate monitoring and control functions as well. Therefore, protection as well as monitoring functions must be considered when applying the low frequency input signals.

As mentioned in point a), in VFD applications, the frequency of the motor input current signals during starting varies from low frequency to the desired frequency level with a defined rate of change. Moreover, some applications require the motor to run at off-nominal frequency (speed) during the normal load conditions. Therefore, depending on the motor running condition, measurement error varies with the varying frequency.

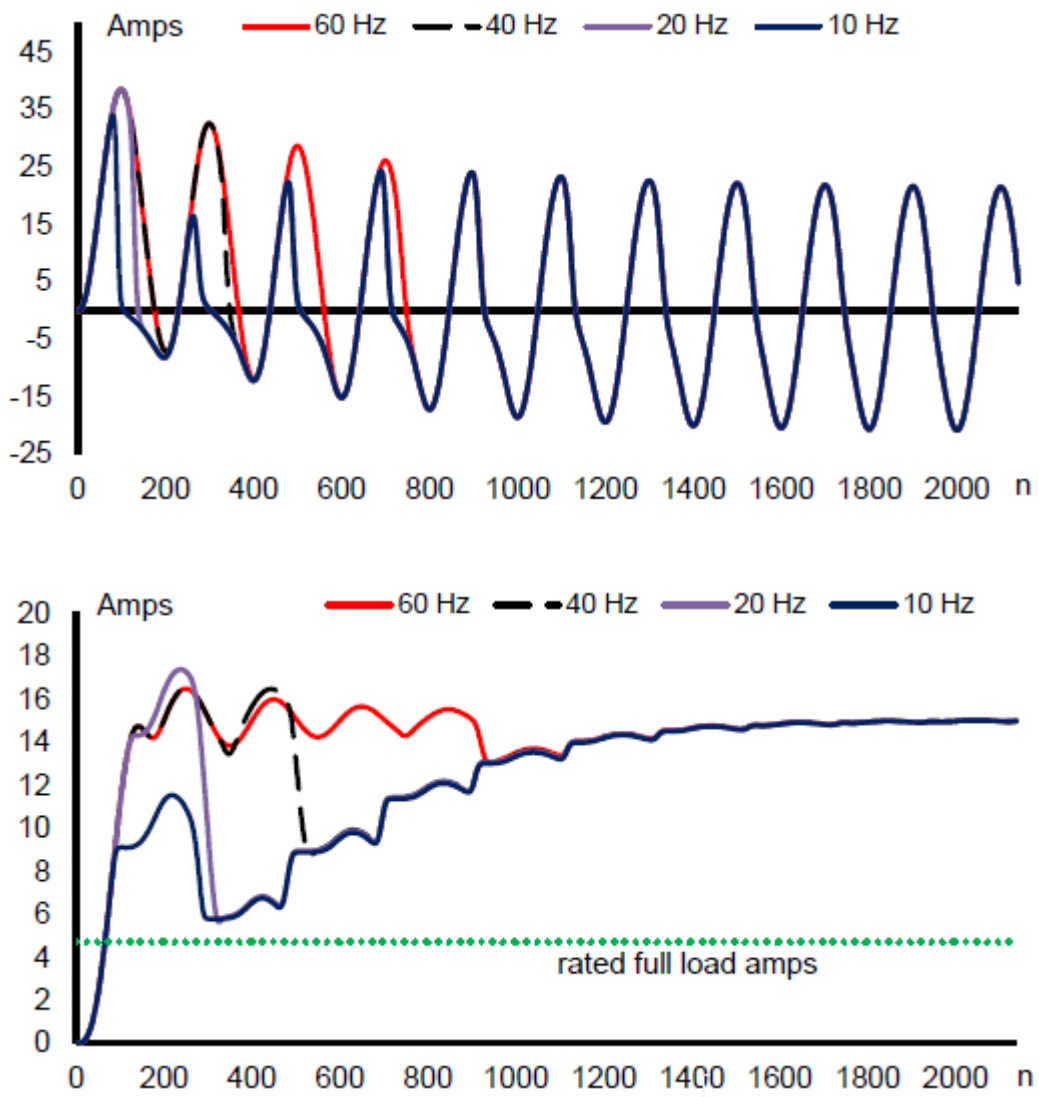


Figure 10.3 Sinusoidal and RMS Measurement of the Steady State Short Circuit Secondary Current

Undercurrent protection typically uses fundamental currents (DFT-type) to detect loss of load or undercurrent operating conditions of the motor. However, it is important to block the undercurrent protection during motor starting. The reason is: during motor starting, the current magnitude measurement (DFT-type) may remain below the undercurrent threshold for some duration of time until the current reaches the undercurrent threshold level. Duration of block time depends on the provision of tracking frequency.

Differential protection performance during external fault: Single- or dual-slope characteristic and higher pickup are typically used to prevent mal-operation of the differential protection in the event of an external fault with CT saturation. However, it won't impact the differential operation because both ends CTs see the same low frequency currents resulting in zero or very small false differential current measurement.
Differential protection performance during internal fault: However, in case of the internal fault terminal CTs will see a high fault current. Differential protection must now operate to isolate the motor from the system. However, when VFD fed motor is operating at low frequency, fault current can saturate the CT if not properly selected. Operation of the differential protection may be in jeopardy, if differential is set not too sensitive.

Overcurrent protection can be affected in the VFD motor application when motor is running at low speed or low frequency. Fig. 10.4 shows that when CT is properly selected considering low frequency into account, overcurrent correctly operates as soon as the primary current reaches the pickup level. However, in case of CT saturation, secondary current doesn't replicate the primary current and reaches the pickup level after 33msec, resulting in delayed operation of the overcurrent, which can result in the severe damage to the motor as energy accumulation in the low frequency currents is significantly very large compared to higher frequency. This problem can be solved by (1) proper selection of current transformer (2) lower setting of the overcurrent pickup level, care must be taken that overcurrent must be select about the maximum allowable load current that equals SF x FLA.

Many of the today's digital relays provide multi setpoint groups; when required protection settings can be switched to different settings for a different operating condition. In VFD

motor applications having prolonged low frequency motor operation, adjustment to the protection settings can be achieved by automatic switching between groups at different frequency levels.

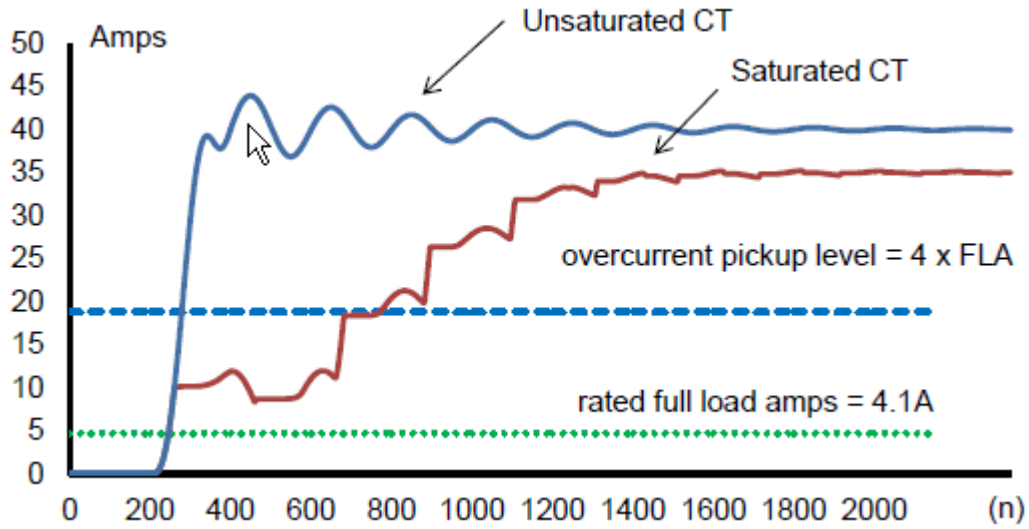
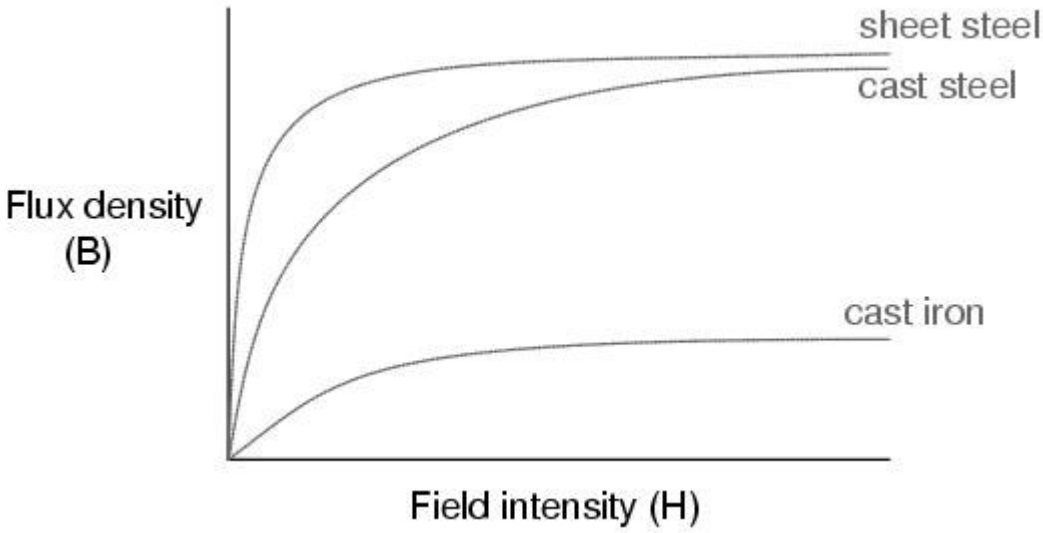


Figure 10.4 Sinusoidal and RMS Measurement of the Steady State Short Circuit Secondary Current

APPENDIX 11

Permeability and Saturation

The nonlinearity of material permeability may be graphed for better understanding. We'll place the quantity of field intensity (H), equal to field force (mmf) divided by the length of the material, on the horizontal axis of the graph. On the vertical axis, we'll place the quantity of flux density (B), equal to total flux divided by the cross-sectional area of the material. We will use the quantities of field intensity (H) and flux density (B) instead of field force (mmf) and total flux (Φ) so that the shape of our graph remains independent of the physical dimensions of our test material. What we're trying to do here is show a mathematical relationship between field force and flux for *any* chunk of a particular substance, in the same spirit as describing a material's *specific resistance* in ohm-cmil/ft instead of its actual *resistance* in ohms.

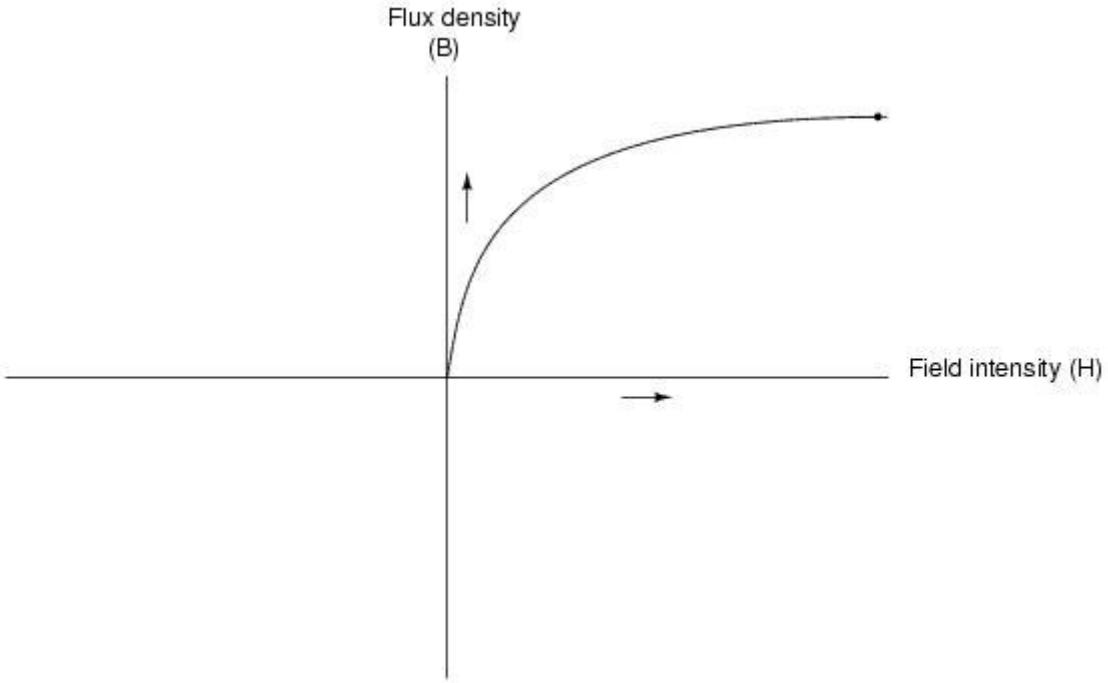


This is called the *normal magnetization curve*, or *B-H curve*, for any particular material. Notice how the flux density for any of the above materials (cast iron, cast steel, and sheet steel) levels off with increasing amounts of field intensity. This effect is known as *saturation*. When there is little applied magnetic force (low H), only a few atoms are in alignment, and

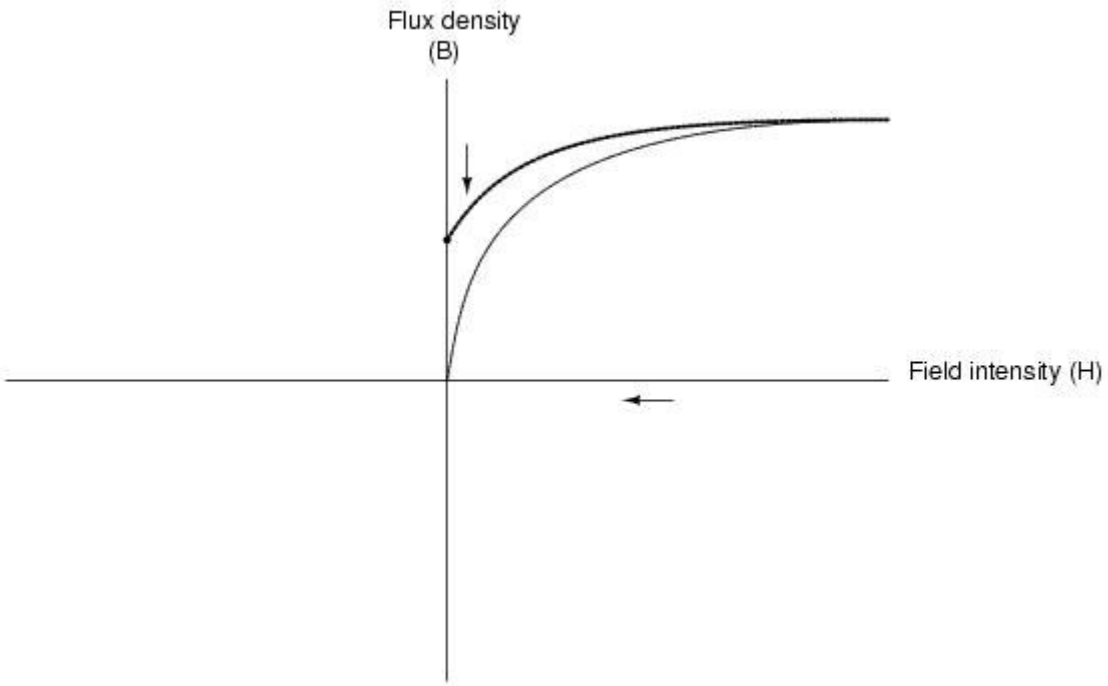
the rest are easily aligned with additional force. However, as more flux gets crammed into the same cross-sectional area of a ferromagnetic material, fewer atoms are available within that material to align their electrons with additional force, and so it takes more and more force (H) to get less and less "help" from the material in creating more flux density (B). To put this in economic terms, we're seeing a case of diminishing returns (B) on our investment (H). Saturation is a phenomenon limited to iron-core electromagnets. Air-core electromagnets don't saturate, but on the other hand they don't produce nearly as much magnetic flux as a ferromagnetic core for the same number of wire turns and current.

Another quirk to confound our analysis of magnetic flux versus force is the phenomenon of magnetic *hysteresis*. As a general term, hysteresis means a lag between input and output in a system upon a change in direction. Anyone who's ever driven an old automobile with "loose" steering knows what hysteresis is: to change from turning left to turning right (or visa-versa), you must rotate the steering wheel an additional amount to overcome the built-in "lag" in the mechanical linkage system between the steering wheel and the front wheels of the car. In a magnetic system, hysteresis is seen in a ferromagnetic material that tends to stay magnetized after an applied field force has been removed (see "retentivity" in the first section of this chapter), if the force is reversed in polarity.

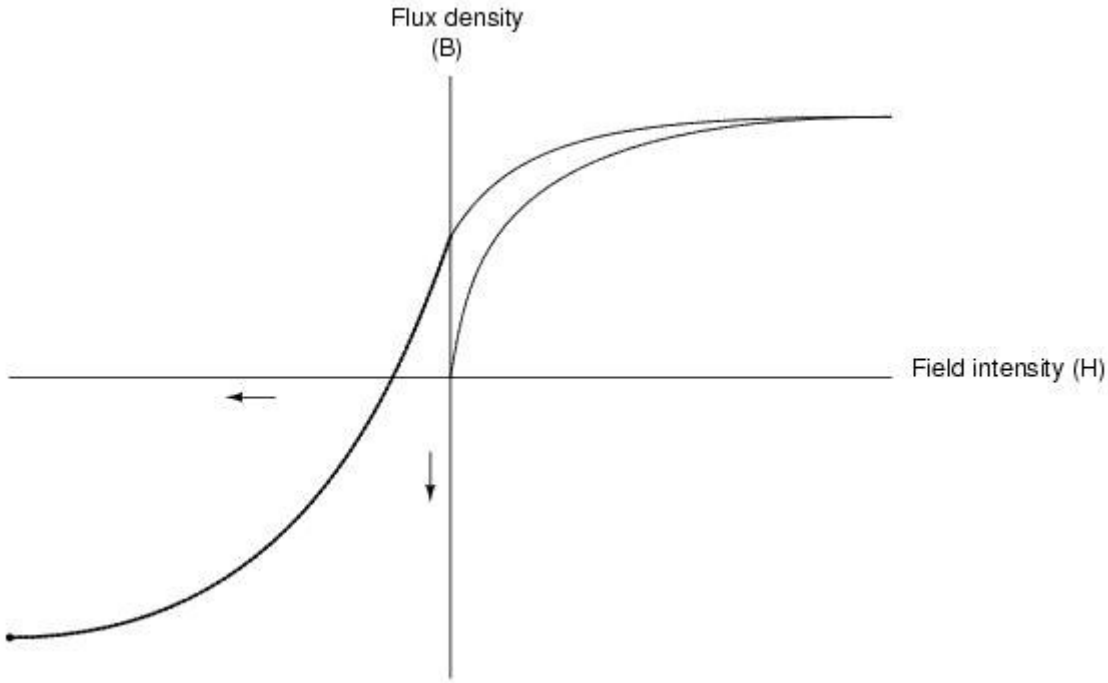
Let's use the same graph again, only extending the axes to indicate both positive and negative quantities. First, we'll apply an increasing field force (current through the coils of our electromagnet). We should see the flux density increase (go up and to the right) according to the normal magnetization curve:



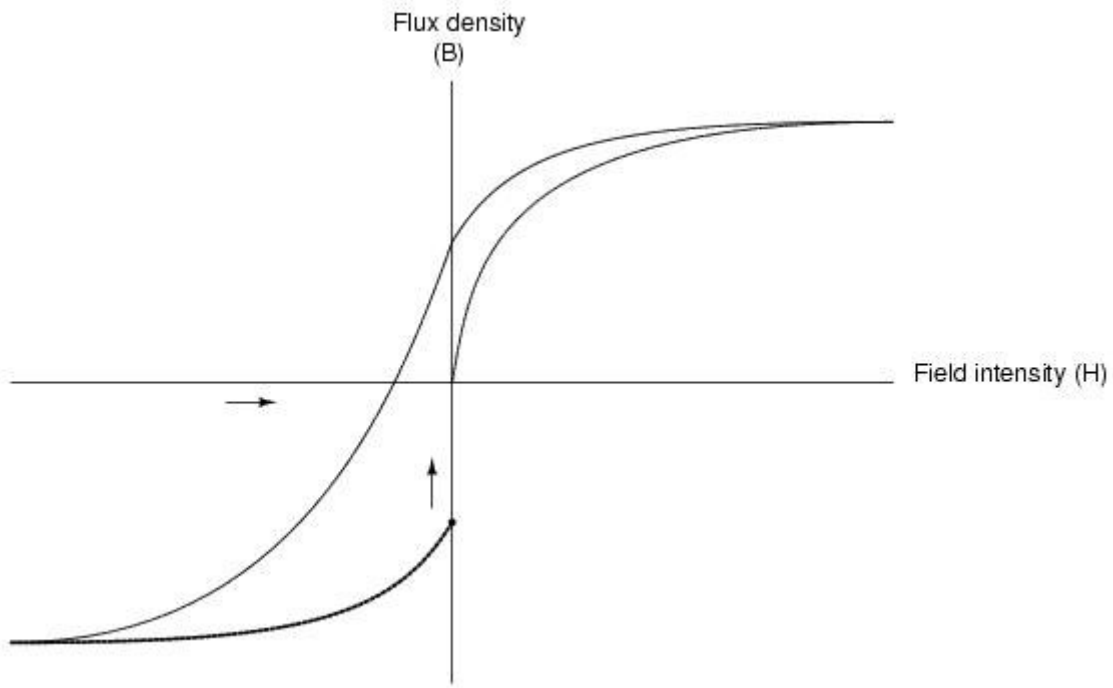
Next, we'll stop the current going through the coil of the electromagnet and see what happens to the flux, leaving the first curve still on the graph:



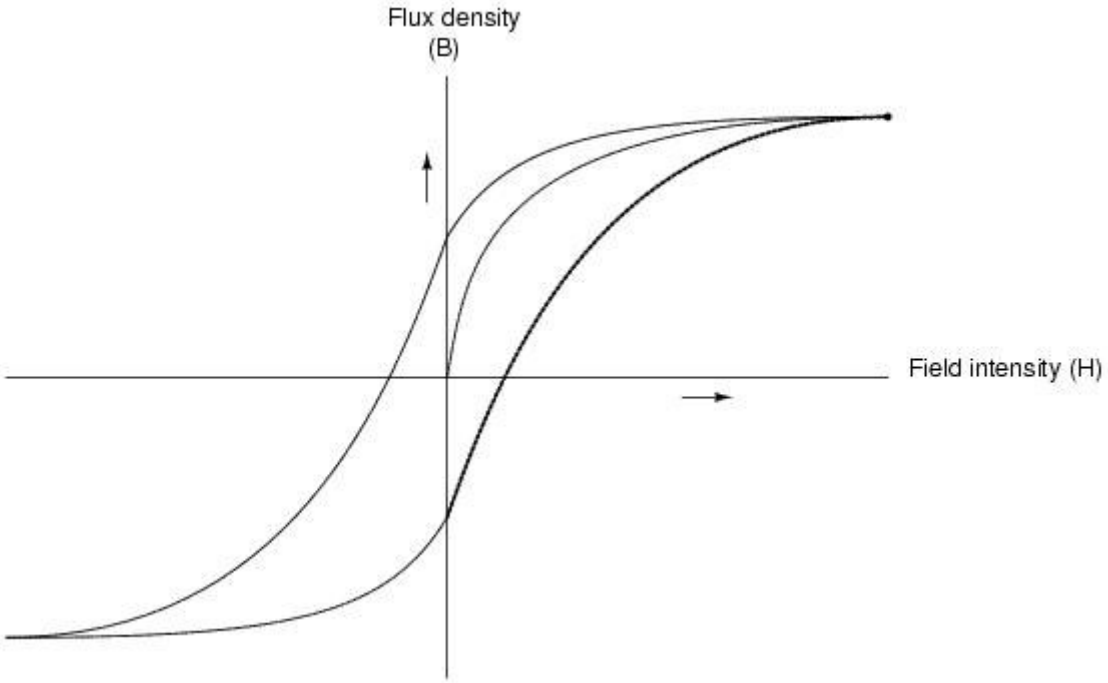
Due to the retentivity of the material, we still have a magnetic flux with no applied force (no current through the coil). Our electromagnet core is acting as a permanent magnet at this point. Now we will slowly apply the same amount of magnetic field force in the *opposite* direction to our sample:



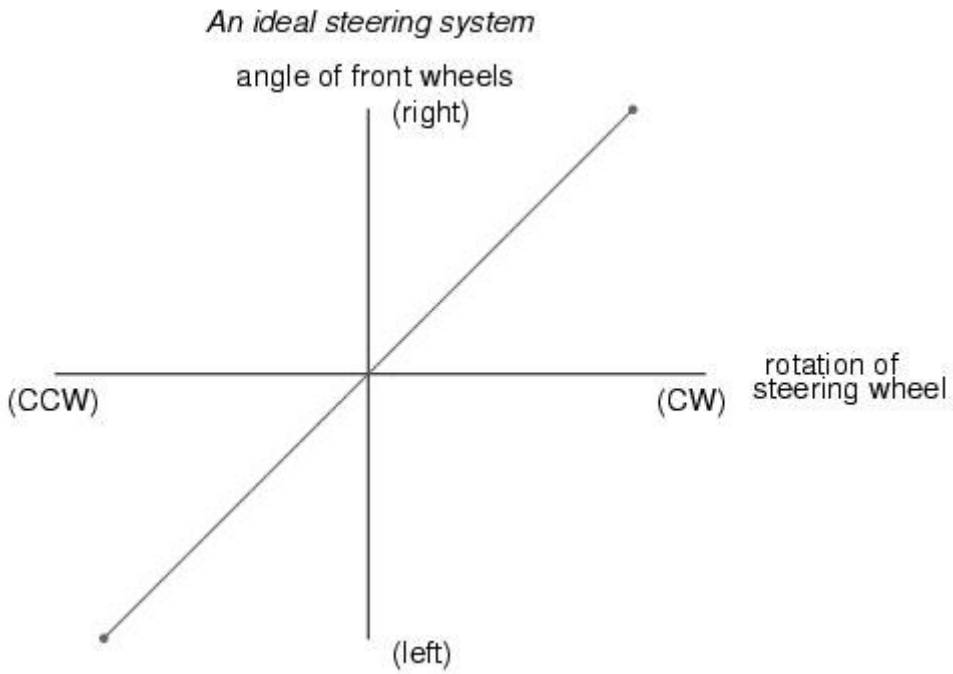
The flux density has now reached a point equivalent to what it was with a full positive value of field intensity (H), except in the negative, or opposite, direction. Let's stop the current going through the coil again and see how much flux remains:

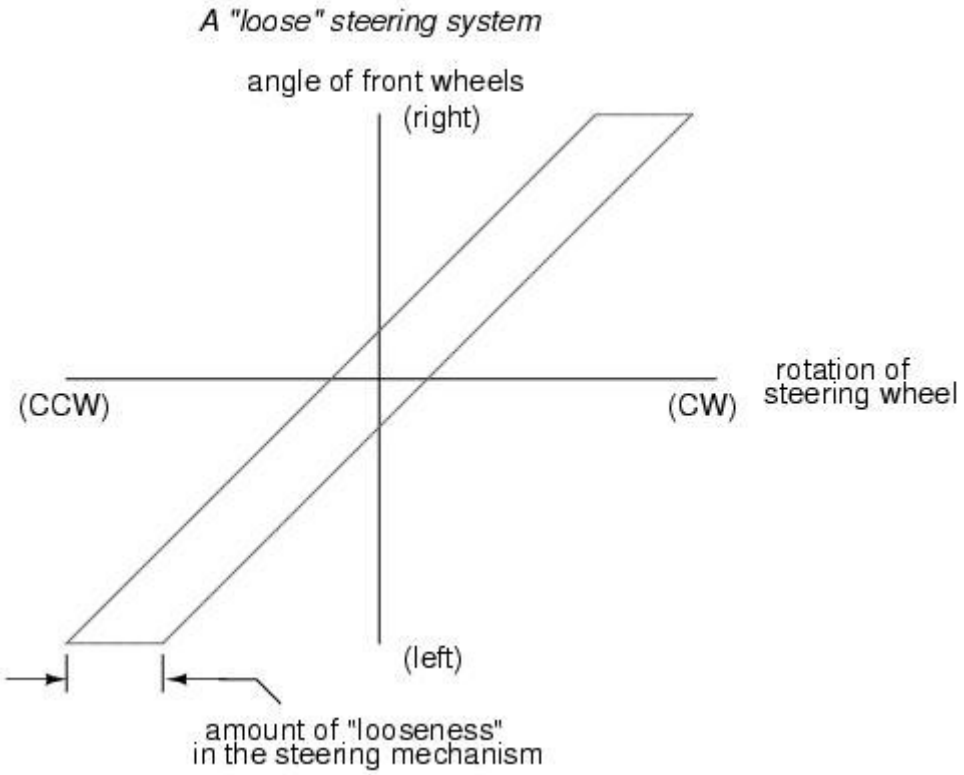


Once again, due to the natural retentivity of the material, it will hold a magnetic flux with no power applied to the coil, except this time it's in a direction opposite to that of the last time we stopped current through the coil. If we re-apply power in a positive direction again, we should see the flux density reach its prior peak in the upper-right corner of the graph again:



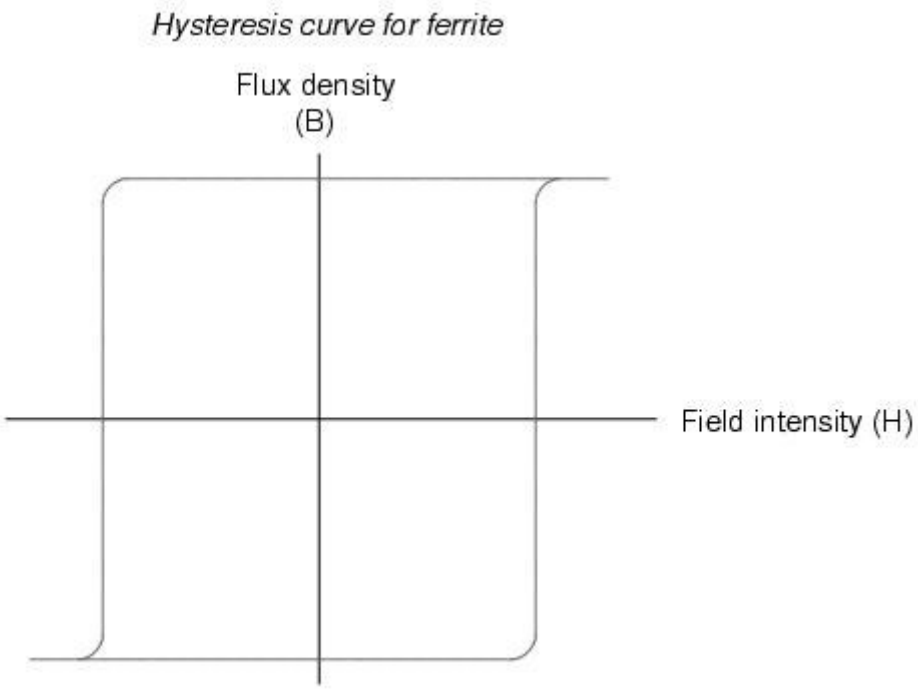
The "S"-shaped curve traced by these steps form what is called the *hysteresis curve* of a ferromagnetic material for a given set of field intensity extremes (-H and +H). If this doesn't quite make sense, consider a hysteresis graph for the automobile steering scenario described earlier, one graph depicting a "tight" steering system and one depicting a "loose" system:


An ideal steering system
angle of front wheels
(right)
(CCW)
(CW)
rotation of
steering wheel
(left)


A "loose" steering system
angle of front wheels
(right)
(CCW)
(CW)
rotation of
steering wheel
(left)
amount of "looseness"
in the steering mechanism

Just as in the case of automobile steering systems, hysteresis can be a problem. If you're designing a system to produce precise amounts of magnetic field flux for given amounts of current, hysteresis may hinder this design goal (due to the fact that the amount of flux density would depend on the current *and* how strongly it was magnetized before!). Similarly, a loose steering system is unacceptable in a race car, where precise, repeatable steering response is a necessity. Also, having to overcome prior magnetization in an electromagnet can be a waste of energy if the current used to energize the coil is alternating back and forth (AC). The area within the hysteresis curve gives a rough estimate of the amount of this wasted energy.

Other times, magnetic hysteresis is a desirable thing. Such is the case when magnetic materials are used as a means of storing information (computer disks, audio and video tapes). In these applications, it is desirable to be able to magnetize a speck of iron oxide (ferrite) and rely on that material's retentivity to "remember" its last magnetized state. Another productive application for magnetic hysteresis is in filtering high-frequency electromagnetic "noise" (rapidly alternating surges of voltage) from signal wiring by running those wires through the middle of a ferrite ring. The energy consumed in overcoming the hysteresis of ferrite attenuates the strength of the "noise" signal. Interestingly enough, the hysteresis curve of ferrite is quite extreme:



REVIEW:

- The permeability of a material changes with the amount of magnetic flux forced through it.
- The specific relationship of force to flux (field intensity H to flux density B) is graphed in a form called the *normal magnetization curve*.
- It is possible to apply so much magnetic field force to a ferromagnetic material that no more flux can be crammed into it. This condition is known as magnetic *saturation*.
- When the *retentivity* of a ferromagnetic substance interferes with its re-magnetization in the opposite direction, a condition known as *hysteresis* occurs.

APPENDIX 12

Terms and Definitions

1. Rated Primary Short-circuit Current (IPrimarysc)

RMS value of the primary symmetrical short-circuit current on which the rated accuracy performance of the current transformer is based.

2. Instantaneous Error Current (Iε)

Difference between instantaneous values of the primary current and the product of the turns ratio times the instantaneous values of the secondary current. When both alternating current and direct current components are present, Iε must be computed as the sum of both constituent components:

$$I\varepsilon = I\varepsilon\ ac + I\varepsilon\ dc = (\ n * ISecondary\ ac - IPrimary\ ac\ ) + (n * ISecondary\ dc - IPrimary\ dc\ )$$

3. Peak Instantaneous Error (ξi)

Maximum instantaneous error current for the specified duty cycle, expressed as a percentage of the peak instantaneous value of the rated primary short-circuit current

4. Peak Instantaneous Alternating Current Component Error (ξac)

Maximum instantaneous error of the alternating current component expressed as a percentage of the peak instantaneous value of the rated primary short-circuit current.

$$\xi ac = 100 * I\varepsilon\ ac\ \ /\ (\sqrt{2} * IPrimary\ Short\text{-}circuit) \quad (\%)$$

5. Accuracy Class

Defined by the “Class Index” followed by the letter P

6. Class Index

Accuracy limit defined by composite error (ξc) with the steady state symmetrical primary current. This number indicates the upper limit of the composite error at the maximum accuracy current feeding the accuracy load. The standard class indexes are 5 and 10.
There is no limit for remnant flux.

7. Limit Factor

This is the ratio between the limit accuracy current and the rated primary current. For protection applications this factor normally is 10 or 20

8. Class P Current Transformer

Indicates "Protection" current transformers destined to feed protection relays. Accuracy limit is defined by composite error ξac with steady state symmetrical primary current.
There is no limit for remnant flux.

9. Class TPS Current Transformer

Low leakage flux current transformer for which performance is defined by the secondary excitation characteristics and turns ratio error limits. There is no limit for remnant flux.

10. Class TPX Current transformer

Accuracy limit defined by peak instantaneous error (ξi) during specified transient duty cycle.
There is no limit for remnant flux.

11. Class TPY Current Transformer

Accuracy limit defined by peak instantaneous error (ξi) during specified transient duty cycle.
Remnant flux does not exceed 10% of the saturation flux.

12. Class TPZ Current Transformer

Accuracy limit defined by peak instantaneous alternating current component error (ξac) during single energization with maximum dc. offset at specified secondary loop time

constant. No requirements for dc. component error limit. Remnant flux to be practically null.

13. Primary Time Constant (Tp)

That specified value of the time constant of the dc. component of the primary current on which the performance of the current transformer is based.

14. Secondary Loop Time Constant (Ts)

Value of the time constant of the secondary loop of the current transformer obtained from the sum of the magnetizing and the leakage inductance (Ls) and the secondary loop resistance (Rs).

Normally this value is higher as compared with Tp in TPS class current transformers (about 10s).

Ts will depend on the precision requirements but normally oscillates between 0.3 and 1 seconds for TPY class current transformers.

Finally, Ts is much more lower in TPZ class current transformers (about 0.07 seconds).

15. Time to Maximum Flux (t φ max)

Elapsed time during a prescribed energization period at which the transient flux in a current transformer core achieves maximum value, it being assumed that saturation of the core does not occur.

16. Secondary Winding Resistance (RCT)

Secondary winding dc. resistance in Ohms, corrected to 75º C, unless otherwise specified, and inclusive of all external burden connected.

17. Secondary Loop or Burden Resistance (RB)

Total resistance of the secondary circuit, unless otherwise specified, and inclusive of all external burden connected.

18. Low Leakage Flux Current Transformer

Current transformer for which a knowledge of the secondary excitation characteristic and secondary winding resistance is sufficient for an assessment of its transient performance. This is true for any combination of burden and duty cycle at rated or lower value of primary symmetrical short-circuit current up to the theoretical limit of the current transformer determined from the secondary excitation characteristic.

19. Saturation Flux(ΨS)

That peak value of the flux which would exist in a core in the transition from the non-saturated to the fully saturated condition. This regards to the point on the B-H characteristic of the core at which a 10% increase in B Causes H to be increased by 50%.

20. Remnant Flux (ΨR)

That value of flux which would remain in the core three minutes after the interruption of an exciting current of sufficient magnitude as to induce the saturation flux (ΨS).

21. Saturation Time

It is the time from the fault inception up to CT saturation starts.

22. Vkp

It is the knee point voltage of the magnetizing curve of the CT. This point generally represents the 80% of the full saturation voltage.

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